




DCUSA Consultation 2		At what stage is this document in the process?
<h1>DCP 461</h1> <h2>Reducing the impact of Transmission Distribution Charges</h2> <p>Date Raised: 13 August 2025</p> <p>Proposer Name: Ben Godfrey</p> <p>Company Name: National Grid Electricity Distribution</p> <p>Party Category: DNO</p>		01 – Change Proposal
		02 – Consultation
		03 – Change Report
		04 – Change Declaration
<p>Purpose of Change Proposal</p> <p>To address a growing set of structural, economic, and policy misalignments that are actively hindering the UK's energy transition.</p>		
	<p>This document is the second of two consultations issued to DCUSA Parties and any other interested Parties in accordance with Clause 11.14 of the DCUSA.</p> <p>This consultation seeks industry views on solutions developed under this Change Proposal (“CP”) and DCPs 461A, 461B and 461C. See section 2 for more details on the approach taken by the Working Group.</p> <p>Parties are invited to consider the questions set in section 13 and submit comments using the form attached as Attachment 2 to dcusa@electralink.co.uk by 29 May 2026.</p>	
	<p>Impacted Parties</p> <p>DNOs, IDNOs, Suppliers and CVA Registrants</p>	
	<p>Impacted Clauses</p> <p>Schedule 22</p> <p>Electricity Distribution Licence Special Condition 1.1</p>	

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Any questions?

Contact

Code Administrator



dcusa@electralink.co.uk



0207 432 3011

Proposer

Ben Godfrey



bgodfrey@nationalgrid.co.uk

Timetable

Activity	Date
Initial Assessment Report	13 August 2025
First Consultation Issued	6 November 2025
Second Consultation Issued	06 May 2026
Change Report Approved by Panel	19 August 2026
Change Report issued for Voting	20 August 2026
Party Voting Closes	10 September 2026
Change Declaration Issued to Parties	14 September 2026

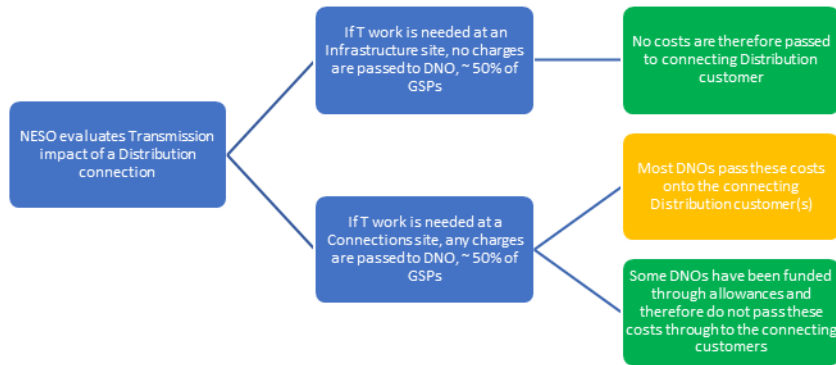
1 Summary

What?

- 1.1 The current regulatory framework for transmission boundary reinforcement charges can create a significant barrier to the timely and cost-effective connection of new generation and demand customers. Under existing arrangements, most Distribution Network Operators (“DNOs”) are generally not explicitly funded to cover the costs of transmission reinforcement works triggered by customer connections at connection asset Grid Supply Points (“GSPs”). As a result, these costs are generally passed directly and fully to the initiating customer, often requiring substantial upfront capital contributions. However, this is not the case in all instances as the classification of a particular GSP can result in no charges being passed to the DNO. This results in inconsistencies between whether a connection customer is at risk for charges or not.

Why?

- 1.2 The current approach to charging for transmission reinforcement results in different charging outcomes depending on the classification of transmission assets at a GSP in accordance with the Connection and Use of System Code (“CUSC”) charging methodology. For simplicity, if transmission assets at the GSP are (or will) be shared, i.e. utilised by more than one party, this is referred to as an ‘Infrastructure Site’, and any costs of upgrades of any shared transmission assets at the existing GSP or shared transmission assets at new GSPs are not passed on to the DNO, therefore any distribution connecting customer is not exposed to these costs. However, if the transmission assets needed by the DNO at a GSP are not shared, then the costs of those transmission assets are passed onto the DNO and this is referred to as a Connection Site.
- 1.3 Where transmission assets are not shared, there are different approaches on treatment of these costs across DNOs but generally, the DNO will then pass these costs onto the distribution connecting customer or customers. This can place an unsustainable financial burden on individual customers, such as those seeking to connect low-carbon generation or large-scale demand. In this situation, these customers would be required to fully fund transmission upgrades upfront. This may create a high-risk environment that deters investment, stalls projects, and leads to inefficient utilisation of the network. The Proposer argues that reform is essential to enable strategic, coordinated investment in the grid, support decarbonisation, and ensure that the costs of enabling infrastructure are shared appropriately across beneficiaries.
- 1.4 These differences in terms of connection cost recovery are shown in the diagram below and further described in the Working Group Assessment.



How?

- 1.5 The variation in cost recovery approach is creating confusion and different outcomes for customers. Options should be considered to improve the customer experience, being cognisant of timescales to implement, standardisation across regions and voltage levels, impact of current/future price controls, impact on developer investment confidence, and the impact on the generality of customers.
- 1.6 Previously completed work had developed numerous options to be considered by any change proposals/modifications raised:
 - fully socialise via DUoS (“Distribution Use of System charges”), with or without a High Cost Cap;
 - fully socialise via TNUoS (“Transmission Network Use of System Charges”);
 - MW (“megawatt”) minimum threshold and ‘Standard Rate’ above that threshold;
 - customer apportioned costs with unallocated capacity socialised by DUoS; and
 - stronger and more consistent guidance for customers.
- 1.7 The Working Group considered that fully socialising through TNUoS is out of scope of this CP, as it would require progression through a CUSC modification, and that the Standard Rate above would not be cost reflective. As such, these options were not progressed by the Working Group.
- 1.8 Due to the potential impact on both the DCUSA and CUSC, parallel code modifications were considered by the Working Group, however the Working Group agreed to progress this CP at pace to provide a solution in time for ED3 (the third electricity distribution price control period that commences on 1 April 2028).

2 Approach

- 2.1 It should be noted that the original Change Proposal form identifies two separate defects that need to be address:
 - 2.1.1 the risk of a variable and unsustainable financial burden on individual customers in those DNO areas which pass through all transmission-related connections costs, leading to a

“last connectee standing” issue, where if other projects drop out from quoted works, the cost is charged in full to the last customer; and

- 2.1.2 the different treatment of costs in the CUSC charging methodology leading to a “post code lottery” issue, whereby the costs to the distribution connecting customer for transmission reinforcement works are dependent on decisions outside the customer’s or DNO’s control, and which may be made on the basis of efficiency for the transmission network, or where, for some DNO areas, costs are not passed onto the customer at all.
- 2.2 The Working Group identified nine options, which were consulted on, four of which relate to each of the identified defects above, and one of which retains the status quo but with additional clarity placed within the existing legal text to bring consistency across DNOs. Following the first consultation, the Working Group agreed to progress up to seven of these options (depending on further work.)
- 2.3 The Working Group recognised a limitation in the DCUSA, which allows for a maximum of four options to be presented for voting under each Change Proposal (the original proposal and up to three alternatives), which meant it would not be possible to progress all the identified solutions under DCP 461.
- 2.4 To facilitate progress on the various options under consideration, the Working Group may raise additional Change Proposals (CPs) in parallel with the development of this consultation. The options outlined within this consultation will be incorporated into the relevant change proposals following the conclusion of the consultation phase, and will form part of the change report phase prior to being presented to Parties for voting.

3 Governance

- 3.1 This CP is likely to impact competition in the distribution and transmission of electricity and will impact on the charges faced by both (i) a customer requesting a new/modified connection, such as those seeking to connect low-carbon generation or large-scale demand, and (ii) the generality of customers through increased DUoS charges. This CP has therefore been raised as a Part 1 Matter, and the solutions will be submitted to the Authority for a decision.

4 Why Change?

- 4.1 Customers connecting at Distribution can have an impact on the Transmission network and the CUSC sets out which projects are required to undertake what is known as a Transmission Evaluation Assessment (“TEA”). The result of that assessment might identify that there is transmission work needed to facilitate the connection. If that is the case, then there are numerous factors that affect whether the connecting customer is charged or not.

Transmission charging

4.2 Section 14 (Charging Methodologies) of the CUSC sets out how transmission system costs are recovered. In simple terms cost-recovery varies depending on whether the assets are 'connection assets' or 'infrastructure assets':

4.2.1 Connection assets are recovered via connection charges to a single user in accordance with the CUSC. A DNO is seen as a single user even if there are multiple embedded customers connected to that DNO's connection to the transmission network) and relate to assets solely required to connect that user to the transmission system; and

4.2.2 Infrastructure assets are recovered via TNUoS charges and relate to assets shared by multiple transmission connected users.

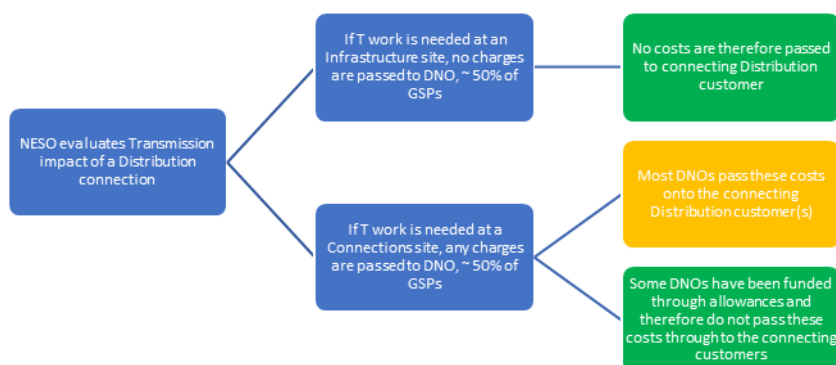
Distribution charging

4.3 Whether or not the DNO is exposed to any charges therefore first depends on the categorisation of the transmission assets at GSP as described in 4.2. Only in the situation where the GSP is a Connection Site (as per 1.2 above) does the National Energy System Operator ("NESO") pass through the costs to the DNO. In these instances, there are different treatments of the costs by DNOs. These are described at a high-level below, noting there are further subtleties between the approaches that have not been brought out for simplicity.

4.4 DNOs' approaches to recovering the capital components of these costs differ, with some effectively passing these costs through to the connection customer(s) that have triggered the transmission work via the distribution connection charge, while others have received price control funding to socialise those costs via DUoS customers.

4.5 If in the case of the former (costs recovered via the distribution connection charge), there is more than one customer, the costs are shared between them based on the relative capacities requested. Only if these connection offers are accepted does the DNO accept the offer from NESO and the work progress.

4.6 This is shown in the diagram below with the green boxes showing where the connecting customer does not receive a charge and the yellow box where they do.



4.7 The CUSC therefore creates a situation where costs may be recovered by the DNO or through the TNUoS charges depending on the classification of the relevant transmission assets. CMP

460 has been raised to review this treatment. Whilst it is out of scope for this CP to modify the CUSC charging arrangements, it can look to address charging differences for amounts to be recovered by DNOs. Note, any solutions proposed may be superseded by any changes to the CUSC. This CP therefore looks to develop solutions to address these different outcomes dependent on the GSP a distribution customer is being connected to.

- 4.8 For a GSP that is a Connection Site, a DNO's regulatory and commercial obligations (in lieu of allowed regulatory funding and varying interpretation of Clause 1.73 of Schedule 22 of the DCUSA) places the full capital cost of the relevant transmission reinforcement on the customer(s) that trigger(s) the need for upgrades – often requiring large, upfront capital contributions. This approach risks creating a disproportionate financial burden, such as for low-carbon and community energy projects, and introduces significant investment risk. Even where there are multiple distribution connected customers and the costs are shared amongst them, the cost liability for any given customer can change based on the actions of other customers. If one customer's connection offer is ended, either by them cancelling or being terminated, the costs are redistributed amongst the remaining customers. This could end up with all the costs falling to the "last connectee standing" and make the project unviable.
- 4.9 These distortions may hinder the timely connection of new generation and demand and slow down progress toward decarbonisation targets. The Proposer's view is that change is essential to ensure a fairer, more predictable, and strategically aligned charging regime that supports the energy transition and enables efficient network development.
- 4.10 However, an opposing view is that changing the arrangements such that a DNO recovers some or all of these costs via DUoS charges reduces or removes a locational cost signal for new projects. This would place a greater cost burden on the generality of customers, including those most vulnerable. An alternative solution is to standardise the current approach across all DNOs so that all relevant transmission costs (the capital components) are recovered via distribution connection charges. This solution does not address the inconsistencies with differing treatment for an Infrastructure Site and a Connection Site, but this is in scope of CMP 460.

5 Consultation 1 Working Group Assessment

- 5.1 The content of this section of the consultation document has already been consulted on and is provided for background and context. The Working Group's review and conclusions can be found in sections 5 and 6 of this document.
- 5.2 The DCUSA Panel established a Working Group to assess this CP. Meetings were held in open session and the minutes and papers of each meeting are available on the [DCUSA website](#).

Relationship to CMP 460

- 5.3 The Working Group considered the relationship between this CP and CMP 460.

- 5.4 The Working Group discussed whether both changes should be aligned and coordinated, resulting in a joined-up approach to resolving the issues, including the timing of consultations, producing the reports and issuing these to the Authority for a decision.
- 5.5 The Working Group discussed the timelines for both changes, noting that the timeline for this CP may need to be tightened up should the Working Group wish to develop the solution(s) in a timeframe that allows the Authority to make a decision in time for implementation for ED3. It was considered that CMP 460 is likely to be significantly more complex given the potential impact on users with local service assets currently classed as infrastructure and potential need to rebalance TNUoS charging. In contrast, the Working Group believes that this CP can be implemented in a much shorter timeframe for a more narrowly focussed change to how DNOs recover the costs of transmission connection works.
- 5.6 The Working Group also noted that although it could be considered beneficial to develop both changes in a coordinated manner, it could not be presumed that either proposal will be approved by the Authority.
- 5.7 The Working Group agreed that this CP should be progressed in isolation, and at pace, in order to deliver solutions for voting and approval in time for inclusion in ED3.

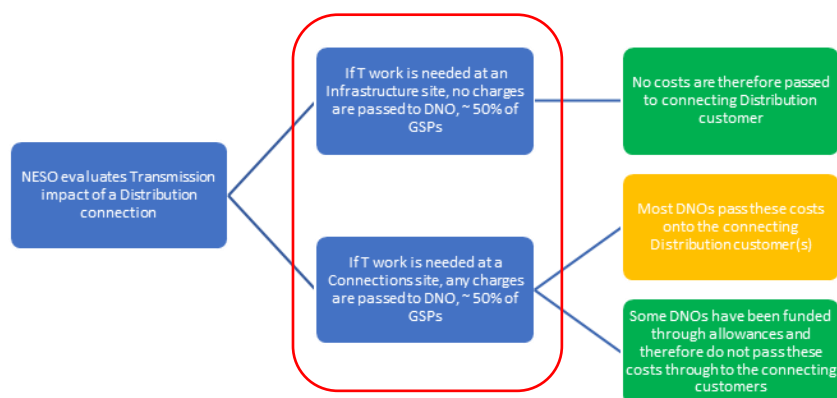
Issues Identified

- 5.8 The Working Group discussed the issues identified in this CP, which it split into two distinct sets of issues:
 - 5.8.1 the different treatment of costs in the CUSC charging methodology; and
 - 5.8.2 the risk of a variable and unsustainable financial burden on individual customers in those DNO areas which pass through all transmission-related connections costs.
- 5.9 The Working Group noted that a single solution may not resolve both of the issues identified and that, in the event there are multiple solutions to be taken forward, it may be necessary for the proposed solutions to be presented either as alternative variations (of which three may be included in the Change Report for this CP) or to be presented under separate CPs.
- 5.10 It was noted that the timescales would be challenging, should a separate CP be required, and it could not be presumed that either/both of the CPs would be approved.
- 5.11 In setting out the issues and potential options for solving them in the following sections, where any option would result in a DNO recovering less transmission costs from the connecting customer (via the distribution connection charge), the Working Group noted that it is not within the scope of this CP to consider how these are recovered but have assumed that these would be recovered via DUoS charges to help stakeholders understand the potential consequences of the different options.
- 5.12 The impact of any options to be taken forward will need to be assessed following this consultation. This will need to include DNO funding in ED3, DNOs' ability to recover the costs via DUoS and

the treatment in ED3. These may have a bearing on the timing of implementation but will be considered in more detail in the next phase of the development of this CP.

Transmission Connection Asset Works Related Charges

- 5.13 The Working Group discussed that this issue arises from the transmission charging regime where an Infrastructure Site and a Connection Site result in different charging outcomes.
- 5.14 It was discussed that, with the forecast increase in infrastructure sites, where a Connection Site becomes shared by two or more transmission users, there is a high likelihood of different treatment arising based on which GSP a connection is made. It was noted (based on information provided by NGED¹) that two categories (Connection Site and Infrastructure Site) are split around half and half across some regions of England and Wales but in some areas Infrastructure Sites currently represent up to 60% (and therefore no charge made to the DNO where transmission work is needed). It was noted that the trend was for an increasing number of Infrastructure Sites as these shared sites may have led to a more efficient economical system in line with the obligations of transmission network company's primary obligations.



- 5.15 The Working Group reviewed four potential solutions to resolve this issue:
- 5.15.1 Option 1.1: no transmission costs passed through to distribution connecting customers, instead to be recovered via DUoS charges;
 - 5.15.2 Option 1.2: variant of 5.15.1: no transmission costs passed through to distribution connecting customers, instead to be recovered via DUoS charges, *unless* the GSP is to feed a single distribution connected customer;
 - 5.15.3 Option 1.3: extend the voltage rule to transmission charges and recover more via DUoS charges; and
 - 5.15.4 Option 1.4: the application of a High-Cost Project Threshold ("HCPT") to limit recovery via DUoS charges.

¹ <https://connecteddata.nationalgrid.co.uk/dataset/gsp-technical-limits>

Option 1.1: No transmission costs passed through to distribution connecting customers, instead to be recovered via DUoS charges

- 5.16 This solution would only apply where the DNO receives charges for any transmission works, i.e. related to a Connection Sites. In these situations, the drafting of the solution would be that the DNO would not pass on any charges to any distribution connecting customers for transmission works. Instead, the costs would be recovered from DUoS customers over the DNOs normal recovery timescales for investment, currently 45 years.
- 5.17 This would completely remove the different cost recovery approaches by DNOs such that distribution connecting customers would not contribute to these costs via the distribution connection charge irrespective of the classification of the GSP. This difference in treatment is outside of the connecting customer's control and removes a perceived risk that only connections to an Infrastructure Site will be financially viable, which could lead to inefficient network design. Note that this would not apply to transmission fees which would still be chargeable to the customer via the distribution connection charge.

Option 1.2: No transmission costs passed through to distribution connecting customers, instead to be recovered via DUoS charges, unless the GSP is to feed a single customer

- 5.18 This solution is the same as Option 1.1 but adds an exception. The exception would only apply to GSPs where there is only one distribution customer connected to it. The drafting of the solution would be along the lines of defining the exception as "wholly or mainly" used by a single customer. This maintains integrity with the distribution charging principle of sole use and shared assets. It also maintains alignment with transmission charging principles so that there are no costs avoided for a single customer seeking to charge at transmission or distribution.
- 5.19 However, it does add complexity to the solution and the Working Group would need to consider how this single use is defined, both at the time of connection and in the future, and whether requested by the customer or driven by unavoidable DNO design outcomes. This solution would remove the anomaly of the charging dependent on the GSP classification (that is outside of the connecting customers control) but maintain broad consistency if it was a single customer connecting to a new GSP specifically at their request.
- 5.20 However, it does add complexity to the solution and the Working Group would need to consider how this single use is defined, both at the time of connection and in the future. This solution would remove the anomaly of the charging dependent on the GSP classification (that is outside of the connecting customers control) but maintain broad consistency if it was a single customer connecting to a new GSP.

Option 1.3: Extend the voltage rule to transmission charges and recover more via DUoS charges

- 5.21 This is an alternative solution to those above. The existing distribution charging principles are, apart from some specific exceptions, based on there being no charges for reinforcement for demand connections and generation connections only pay for any reinforcement at the same

voltage at the point of connection. An alternative solution is to extend these principles to transmission charges.

- 5.22 This would result in demand connections not paying for any transmission work and generation connections would only pay if they were connecting at 132kV and then only for the 132kV element of the transmission work. Generation connections below 132kV would not pay for any transmission works. This solution would remove the anomaly based on the GSP classification in most instances but would retain it for generation connections connecting at 132kV.

Option 1.4: Application of a HCPT to limit recovery via DUoS charges.

- 5.23 This solution is an extra feature that could be added to any of the three solutions above. It would be designed to protect DUoS customers from any extremes of costs. It could follow the principles used to develop the demand high-cost project threshold where the threshold was set to only be triggered for approximately the highest 5% of costs. This means that most projects are unaffected, but any extremely high-cost projects are still subject to a locational cost signal. This would need analysis to be undertaken to set an appropriate threshold.

Summary

- 5.24 The table below summarises the impact of each of the options against a number of perspectives.

	1.1 No T costs passed to D	1.2 As 1.1 with exception for only one customer	1.3 Extending voltage rule	1.4 Adding HCPT to any of the options
Locational signal	Fully removed	Limited to a single customer at a GSP at 40-50% GSPs	Limited to 132kV connections and only weak signal at 40-50% GSPs	Limited to extreme cases at 40-50% GSPs
Consistency of charging outcome	No charges for any so consistent outcome	No charges apart from single customer at GSP, retains broad alignment with T charging	No charges apart from 132kV connections at a Connection site	Adds further exception for extreme cases
DUoS cost impact	Biggest increase in DUoS costs	Limited reduction from 1.1	Limit reduction compared to 1.1	Removes extreme cases from DUoS
Financial burden	No costs so no financial burden	Extra costs for single customer but aligns with	Limited costs so limited burden	High financial burden for extreme cases but generally removed



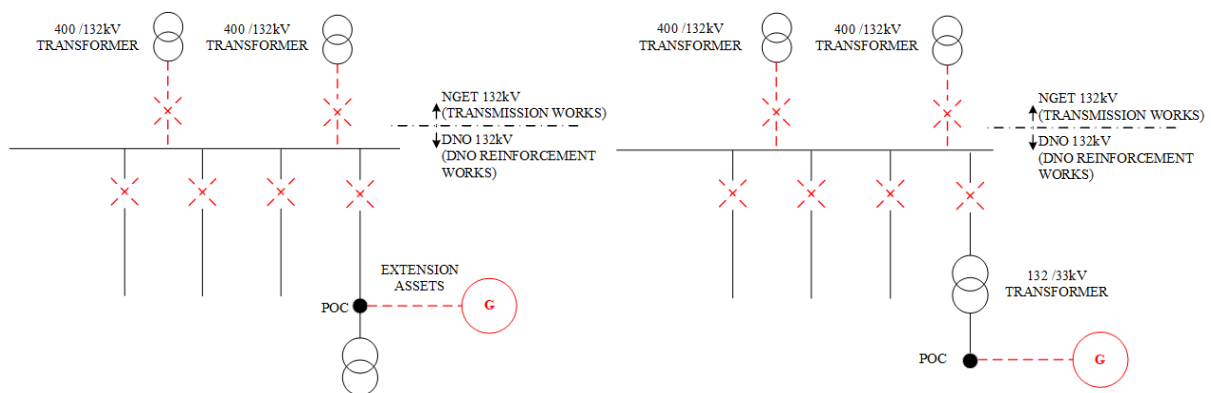
outcome if they
connected at T

Illustrative examples

5.25 The Working Group developed a table to describe each solution, help demonstrate the potential consumer impacts and describe the challenges associated with the development of each option.

5.26 To help illustrate how the different solutions would work, some scenarios have been set out based on a single GSP with three types of connection being made to it:

- a) Generation (60 MW) connecting at 132kV
- b) Generation (20 MW) connecting at 33kV
- c) Generation (4 MW) connecting at HV or below
- d) Demand (80 MVA) connecting at any voltage



5.27 To help illustrate the options, the new GSP is assumed to create 240MW of capacity and cost £60m of which £5m is associated with the 132kV work on the transmission side of the interface.

			a) Generation (60 MW) connecting at 132kV		b) Generation (20 MW) connecting at 33kV		c) Generation (4 MW) connecting at HV		d) Demand (80 MVA) connecting at any voltage	
	Option	Description	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers
1.1	No transmission costs passed through to distribution connecting customers	Simple option whereby all T costs recovered from all DUoS customers.	£0	£60m	£0	£60m	£0	£60m	£0	£60m
1.2	No T costs passed through to individual D connectee unless the GSP is to feed one customer	This is as per 1.1 but with an exception if a new GSP is created “wholly or mainly” for a single customer. It is not meant to apply to where a new customer triggers a GSP and the extra capacity could be used by others.	£60m	£0	£60m	£0			£60m	£0

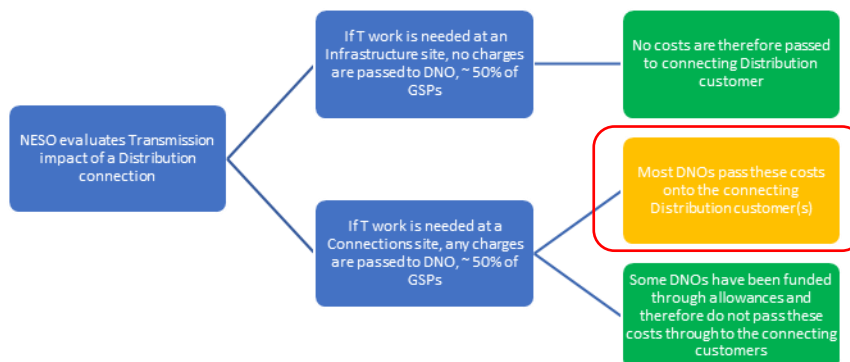
1.3	Extend the voltage rule to T charges	This is an alternative approach which gives different outcomes depending on the type and POC of the D customer. This means that customers only contribute to work at the same voltage level as the POC plus the voltage level above.	£5m	£55m	£0	£60m	£0	£60m	£0	£60m
1.4	Application of a 'High-Cost Project Threshold'	This is an additional feature which could be added to any of the options above. Assuming consistency with the existing HCPT (that applies only to D reinforcement), if the applicable costs are greater than the threshold, then the customer is charged all the applicable reinforcement. Only the reinforcement at the same voltage level plus the one above is considered. Figures assume it is triggered.	£60m	£0	£5m	£55m	£0	£60m	£60m	£0

The risk of a variable and unsustainable financial burden on Individual Customers

5.28 The Working Group discussed that this issue arises where DNOs pass on the costs of any transmission changes to the distribution connecting customers, noting that this is the case for most but not all DNOs. Note also that this only applies to non-Infrastructure sites, representing about 40-50% of GSPs.

Connection cost sharing

5.29 Where there are a number of new customers at a connection GSP, these costs are typically shared based on customers' respective capacities. Should any customers fall away, either by voluntarily withdrawing, being terminated or not meeting Gate 2 requirements, the totality of the costs can fall to the "last person standing". This provides uncertainty and an increase in costs and can happen at any time in the project lifecycle. This creates uncertainty for any given project and could change the commercial viability of a project at any time and when significant investment has been made. It also can result in a situation where a single project has to fund all of the work which poses a significant cost risk, even with the potential for costs to be shared with future connections. The working group considered how these issues could be mitigated.



5.30 The Working Group reviewed four potential solutions to resolve this issue:

5.30.1 Option 2.1 - cost apportionment;

5.30.2 Option 2.2 - cost apportionment with applicability criteria;

5.30.3 Option 2.3 - cost apportionment with a voltage rule applied to transmission charges; and

5.30.4 Option 2.4 - the application of a High-Cost Project Threshold.

Option 2.1 - Cost apportionment

5.31 In this solution, a form of cost apportionment could be applied to any transmission costs so that connecting customers would only pay for a proportion of the costs. This would address both issues identified:

5.31.1 The costs would be a fixed proportion for the individual customers and would not change irrespective of the outcome of other customers contracts; and

5.31.2 The quantum of the costs would be lower as the connecting customer would only pay a proportion of the costs.

5.32 The approach to cost apportionment could mirror the existing ones for distribution but would need to be reviewed. Currently these are based on the proportion of capacity used based on thermal or fault level and a summary is provided as Attachment 3.

Option 2.2 - Cost apportionment with applicability criteria

5.33 This solution builds on Option 2.1 by adding explicit criteria to clarify which connecting customers are exposed to these charges. Without some additional criteria, the costs of the transmission works would in theory be cascaded down to all connections that are made to the GSP. This would otherwise mean that the costs should be passed through to domestic customers connecting at low voltage.

5.34 In this solution, the criteria could be based on the size of the new connection, e.g. for England and Wales this could be aligned to the thresholds for the requirement for a Transmission Evaluation Assessment. Noting that these vary by GSP at either 1MW or 5MW so would need consideration.

5.35 Alternatively, in this solution, the criteria could be based on the voltage level of connection. This could be based on one voltage level to be consistent with how generation is charged or two voltage levels to be consistent with how the HCPT is calculated e.g., for England and Wales this could limit the cost exposure to connections with a Point of Connection voltage of 33kV or higher.

Option 2.3 - Cost apportionment with a voltage rule applied to transmission charges

5.36 This solution would apply a voltage rule to the transmission costs before applying a cost apportionment as in 5.31. This could be based on the existing voltage rule for generation resulting in the connecting customer only pays for a portion of transmission costs at the same voltage as the point of connection. Alternatively, two voltage levels could be applied such that the connecting customer pays for the transmission costs at the same voltage level as the point of connection and the voltage level above.

Option 2.4 - Application of a High-Cost Project Threshold to limit recovery via DUoS.

5.37 This solution is an extra feature that could be added to any of the three solutions above. It would be designed to protect DUoS customers from any extremes of costs. It could follow the principles used to develop the demand high-cost project threshold where the threshold was set to only be triggered for approximately the highest 5% of costs. This means that most projects are unaffected, but any extremely high-cost projects are still subject to a locational cost signal. This would need analysis to be undertaken to set an appropriate threshold.

Summary

5.38 The table below summarises the impact of each of the options against a number of perspectives.

	<u>2.1</u> Cost apportionment	<u>2.2</u> As 2.1 with a threshold	<u>2.3</u> As 2.1 but apply voltage rule	<u>2.4</u> Adding HCPT to any of the options
Locational signal	Some cost signal at 40-50% GSPs but potentially down to LV connections	Some costs at 40-50% GSPs but only those connections above the threshold	Only a cost signal to 132kV connections at 40-50% GSPs	Limited to extreme cases at 40-50% GSPs
Consistency of charging outcome	Potential for costs at only 40-50% of GSPs	Potential for costs at only 40-50% of GSPs	Potential for costs at only 40-50% of GSPs	Potential for costs at only 40-50% of GSPs
DUoS cost impact	Depends on timing and utilisation of the new capacity. If fully used, then little or no impact.	Depends on timing and utilisation of the new capacity. Capacity under the threshold will impact DUoS.	Most of costs will go to DUoS	Adds protection for DUoS from extreme cases.
Financial burden	More proportionate cost if only one connecting customer	More proportionate cost if only one connecting customer	Limited to 132kV connections	Large cost burden on most extreme cases.

Illustrative examples

5.39 As with the first four solutions, the Working Group developed a table to describe each solution, help demonstrate the potential consumer impacts and describe the challenges associated with the development of each option.

			a) Generation (60 MW) connecting at 132kV		b) Generation (20 MW) connecting at 33kV		c) Generation (4 MW) connecting at HV		d) Demand (80 MVA) connecting at any voltage	
	Option	Description	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers
2.1	Cost apportionment	The approach would be for the connecting customer to pay their proportion of the total capacity created.	£15m $\frac{60}{240} \times £60m$	£45m	£5m $\frac{20}{240} \times £60m$	£55m	£1m $\frac{4}{240} \times £60m$	£59m	£20m $\frac{80}{240} \times £60m$	£60m
2.2	Cost apportionment with applicability criteria based on capacity	This would be similar to 2.1 but adding an explicit lower threshold. The threshold could be defined by the size of the new connection eg 5MW. The costs in the table have assumed a threshold of 5MW.	£15m $\frac{60}{240} \times £60m$	£45m	£5m $\frac{20}{240} \times £60m$	£55m	£0 (below threshold)	£60m	£20m $\frac{80}{240} \times £60m$	£60m
2.3	Cost apportionment with the voltage rule applied to transmission charges	This means that customers only contribute to work at the same voltage level as the POC. Cost apportionment would then be applied to the work in scope.	£1.25m $\frac{60}{240} \times £5m$	£58.75m	£0m	£60m	£0	£60m	£1.67m $\frac{80}{240} \times £5m$ Assuming a 132kV connection, otherwise £0	£58.33m

2.4	Application of a High-Cost Project Threshold to limit recovery via DUoS	<p>This is an additional feature which could be added to any of the options above.</p> <p>Assuming consistency with the existing HCPT (that applies only to D reinforcement), if the applicable costs are greater than the threshold, then the customer is charged all the applicable reinforcement. Only the reinforcement at the same voltage level plus the one above is considered. Figures assume it is triggered.</p>	£60m	£0	£5m	£55m	£0	£60	£60m if POC is 132kV £5m if POC is 33kV £0m if POC is HV	£0 if POC is 132kV £55m if POC is 33kV £60m if POC is HV
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Standardised approach

5.40 The working group also considered an option where a consistent approach was applied by all DNOs such that any transmission costs would be charged to the connecting customer or customers that trigger the work.

Option 3.1 - DNO Parties apply a consistent locational signal – no DUoS impact

5.41 This option would standardise the current approach across all DNOs so that all relevant transmission costs (the capital components) are recovered via distribution connection charges. It seeks to promote consistent application across all DNOs, while preserving locational cost signals and protecting DUoS customers from uncontrollable costs with the Electricity Connection Charges Regulation (“ECCR”) providing future safeguards against the financial burden of upfront costs.

Summary

5.42 The table below summarises the impact of this option against a number of perspectives.

	3.1 Cost in full to first comers
Locational signal	Strong location cost signal at 40-50% GSPs.
Consistency of charging outcome	Ensures a consistent approach across all DNOs with potential for costs at only 40-50% of GSPs.
DUoS cost impact	Protects DUoS customers, little or no impact.
Financial burden	High if only one connecting customer. Burden is reduced if multiple customers as costs are shared (but may remain a high burden). The ECCR provides future safeguards against the upfront financial burden.

			a) Generation (60 MW) connecting at 132kV		b) Generation (20 MW) connecting at 33kV		c) Generation (4 MW) connecting at HV		d) Demand (80 MVA) connecting at any voltage	
	Option	Description	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers	Charges to connecting customer	Costs to all DUoS customers
3.1	DNO parties apply a consistent locational signal – no DUoS impact	This proposal clarifies what transmission-related costs DNOs should recover from connecting and wider customers, ensuring consistent application across DNOs. It maintains locational cost signals, protects DUoS customers from uncontrollable costs, and leverages ECCR regulations to reduce future upfront financial burdens	£60m	£0m	£60m	£0m	£60m	£0m	£60m	£0m

Implementation of any changes

- 5.43 The working group discussed the challenges of implementing any changes, particularly due to the differences in current approaches. Working group members identified the desirability of being able to apply any changes to existing contracted projects that are going through Connections Reform.
- 5.44 Overall, the working group considered that a no detriment approach should be taken to implementing any change. Therefore, if any change was approved, it should not result in any increase in costs for existing contracted projects; if it resulted in a reduction in costs then this could be applied more reasonably. For new applications after the implementation date, then the changes would apply.

Consumer Impact/Impact Assessment

- 5.45 The Working Group discussed the need for an impact assessment, noting that each option impacts consumers (with costs being removed from some consumers and socialised across others, to various degrees).
- 5.46 The Working Group also noted the previous send-backs for both DCUSA and CUSC proposals, citing the Authority's assessment that, in each case, the impact assessment was insufficient to allow it to make a decision.
- 5.47 The Working Group discussed the challenges associated with performing an impact assessment for this CP, due to the timescales the Working Group is working towards and the incoming connection reforms, the latter of which will result in some costs being removed but which was, as yet, unquantifiable. It was noted that any impact assessment performed by this Working Group would be invalid, due to the implementation of connection reforms, and would paint a worst-case scenario that, due to its significant materiality, could lead to the rejection of the proposed solution(s) by Parties, through the vote, or by the Authority, based on data which is not a reflection of the future reality.
- 5.48 The Working Group included scenarios in the tables under each set of options, to demonstrate the way that costs could be allocated under each of the options.
- 5.49 The Working Group agreed to revisit the prospects of performing an impact assessment once the solution(s) to be taken forward are determined, following a review of feedback to this consultation, but noted that the same issues pertaining to the accuracy and validity of the impact assessment would likely persist.

6 Consultation 1 Working Group Responses Review

6.1 The first consultation, along with the responses can be found in Attachment 4.

Question 1: Do you understand the intent of the CP?

6.2 The Working Group noted that all respondents understood the intent of the Change Proposal.

6.3 There were 21 respondents in total, consisting of:

- 6.3.1 6 DNOs;
- 6.3.2 1 IDNO;
- 6.3.3 6 Distributed Generators (DG);
- 6.3.4 1 Supplier (jointly a DG);
- 6.3.5 1 Transmission Operator (TO);
- 6.3.6 6 Renewable Energy Developers; and
- 6.3.7 1 Specialist Consultancy for Grid Connections.

6.4 The Working Group noted the varied nature of respondents.

Question 2: Are you supportive of the principle of the CP?

6.5 The Working Group noted the broad support from respondents, whilst also noting some nuances in terms of specific elements supported by some respondents, such as:

- 6.5.1 that it is skewed towards moving costs away from connecting customers and onto the generality of customers;
- 6.5.2 the need for associated licence changes to be made in order to allow charges to be recovered through DUoS, if costs are moved onto the generality of customers;
- 6.5.3 that network upgrades do not benefit only one customer and, as such, any one customer should not necessarily pay for all of the work relating to the upgrade;
- 6.5.4 that option 3.1 may not align with the intent to reduce barriers to entry, may not recognise consumer benefit, and may not encourage efficient network development;
- 6.5.5 that it may relate to scenarios where the transmission GSP asset is not shared at the time of connection and, as such, it may be difficult to justify that upgrade costs are fully or largely socialised, which may in effect be subsidising inefficiently sited non-shared and high-cost assets;
- 6.5.6 that connectees should contribute, at least partly, to upgrade costs of non-shared GSPs, but that there should also be provisions whereby second, third, fourth, etc., comers pay towards upgrade costs;

- 6.5.7 where a non-shared GSP is converted to an infrastructure asset, an appropriate proportion of the upgrade costs should be recovered from network users benefitting from the upgrade; and
- 6.5.8 that, as specified under option 3.1, the first connectee pays for the upgrade costs of non-shared GSPs and are then appropriately reimbursed by additional connectees, as per the ECCR provisions.
- 6.6 A Working Group member noted that Ofgem issued an open letter in July 2025 in relation to deeper connection charges whereas this CP proposes shallower connection charges, and expressed concern that Ofgem may therefore not approve the solution developed under this CP.
- 6.7 The Proposer agreed that care would be needed to not take forward solutions that the Authority may not be minded to approve due to them not aligning with its policy intentions.
- 6.8 A Working Group member observed that the current arrangements could be considered to be “ultra deep” and therefore making the charges shallower may still result in charges that are sufficiently deep.

Question 3: Which of the proposed solutions for the ‘Transmission Connection Asset Works Related Charges’ defect (options 1.1 to 1.4) should the Working Group further develop and present in the change report for voting? Please provide your rationale.

- 6.9 The Working Group noted the suggestion by one respondent that a sliding scale be developed. The Working Group discussed that the creation of a sliding scale is an extra step that the existing distribution runs do not have, which would make this approach out of line with established high-cost project thresholds.
- 6.10 The Working Group noted a comment by one respondent in relation to connections at 33kV triggering transmission reinforcement works. The Working Group discussed that, for option 1.3, anybody connecting at 33kV would not be exposed to any of the transmission reinforcement cost.
- 6.11 The Working Group reviewed noted the following support for options to be explored further:
 - 6.11.1 Option 1.1 – 13 out of 21 respondents supported taking this forward;
 - 6.11.2 Option 1.2 – 11 out of 21 respondents supported taking this forward;
 - 6.11.3 Option 1.3 – 6 out of 21 respondents supported taking this forward; and
 - 6.11.4 Option 1.4 – 9 out of 21 respondents supported taking this forward.
- 6.12 The Working Group noted that options 1.1 and 1.2 had each received support from more than half of respondents. The Working Group agreed to explore options 1.1 and 1.2 further.
- 6.13 The Proposer explained that internal analysis by NGED on option 1.3 showed this option to not do much to recover much of the money, so on balance this did not seem to be a viable option to

take forward. A Working Group member noted that option 1.3 retained small locational signals and was more complicated.

- 6.14 The Proposer noted that some respondents had responded that option 1.4 could be blended into the other two options.
- 6.15 Working Group members agreed to not take option 1.3 forwards due to this solution creating distortion/discrimination into the process between the treatments of demand sites and generation site, as had been highlighted in some responses (including under question 4, the next question), specifically in relation to contributions to shared assets between demand and generation, which is in conflict with the TCR. It was also noted that this would be an overly complex process to draft a solution for.
- 6.16 The Working Group position on whether option 1.4 is to be taken forward is set out in response to the responses to question 4 below.

Question 4: Should any of the proposed solutions referenced in Question 3 not be taken forward? Please provide your rationale.

- 6.17 The Working Group noted one respondent favoured options 1.1 and 1.2 but also considered options 1.3 and 1.4 to be viable, provided the implementation approach followed a 'no detriment' the principle as consulted on under question 8 of consultation 1.
- 6.18 The Working Group discussed the issue raised by one respondent in relation to option 1.3, noting it stated that distortion would arise due to the differences in the way two entities (a generator customer versus a demand customer) would be charged. It was noted that the demand customer (e.g., the data centre, as per the example referenced in this response) connecting at 132kV would not be charged for transmission reinforcement works but a generator connecting at 132kV would be charged.
- 6.19 The Working Group noted that some responses alluded to the added complexity for option 1.3 and that the complexity did not appear to be worthwhile.
- 6.20 The Working Group noted that one respondent raised that option 1.3 would result in undue discrimination between network users in England & Wales versus Scotland.
- 6.21 The Working Group agreed option 1.3 would not be progressed.
- 6.22 The Working Group noted one respondent viewed option 1.4 as impractical because transmission works vary widely, from minor upgrades to entirely new substations, and customers could still face arbitrarily high costs where they trigger a major reinforcement.
- 6.23 The Working Group discussed whether option 1.4 was practical, with the NGET representative explaining that a new GSP may be required because the existing GSP can't be extended further (for a variety of reasons). The new customer would just happen to be the one that triggers the new GSP, regardless of the size of their connection, which may include the building of a brand-

new substation, which is completely outside of the connecting customer's control. It was noted, however, that this would likely not be triggered as it would be economically unviable.

- 6.24 The Working Group also discussed that there is strategic network planning ongoing at this time, which is looking at where grid expansion is most optimal for the wider system. As such, if a user is trying to connect to the network where it is not strategically beneficial, they should be discouraged from doing so if there's a need for a new GSP in that area.
- 6.25 The Working Group noted one respondent had quoted the current high-cost cap threshold of £200/kW could be frequently exceeded by the large costs of Transmission Connection Assets, rendering the code change moot as the final connecting customer risks picking up the full bill.
- 6.26 The Working Group discussed that, for option 1.4, the £200/kW high-cost project threshold would not be used, and a new high-cost project threshold would need to be calculated.
- 6.27 The Working Group discussed the historic thresholds that had been set, in particular around 50kW, as this related to a lot of rural connections where the cost of the work was disproportionate.
- 6.28 The Working Group discussed that this is likely looking at connection asset sites, which are not considered shareable. It was discussed that this option would provide a strong locational signal, so that a small connection (e.g., 5 MW) triggering a GSP is given a signal that the location is not efficient and that they would therefore have to pay for it. The Working Group discussed whether this "check" was needed or whether there were other mechanisms, in the other options under consideration, to resolve this.
- 6.29 The Working Group discussed, in relation to option 1.4, that if the strategic case for reinforcement is put forward for an area of a network, the DNOs will be able to socialise this in some way as it is anticipatory investment. This should attract customers wishing to connect to the network to those areas, as they will not face the high-cost project thresholds since the justification for creating a new GSP at that location has already been made.
- 6.30 The Working Group discussed that, under option 1.4, where a project doesn't accept, and space becomes available, the next customer may be ready to go ahead but could happen to be in an area that triggers new works and high costs, which under this option they would be liable for, which may be a point against taking this option forward. The Working Group noted that a key consideration would be the impact on economic development and growth, and that the principle of the charging methodologies is to recover proportionate costs from connecting customers, both in the present and the future, without killing off growth and development.
- 6.31 The Working Group discussed whether to take option 1.4 forward, with one Working Group member considering this as punitive, arbitrary and lacking an internal consistency, with one Working Group member noting their support was conditional on the correct number for the threshold being determined, and with several Working Group members noting it does not resolve the "last customer standing" issue.
- 6.32 As per paragraph 6.16 above, Working Group members voted (by a show of 9 hands) to not take option 1.4 forwards, with one Working Group Member voted to take option 1.4 forward. However,

the Working Group discussed that if a high-cost project threshold could be determined for option 2.4 (covered later in this document) then this could be applied to option 1.4 and included for consultation and/or voting.

Question 5: Which of the proposed solutions for the ‘risk of a variable and unsustainable financial burden on individual customers’ defect (options 2.1 to 2.4) should the Working Group further develop and present in the change report for voting? Please provide your rationale.

- 6.33 The Working Group noted one respondent stated that where transformers are being installed but only a small amount of additional firm capacity is unlocked due to the running arrangement, CAF may be disproportionately high.
- 6.34 A Working Group member explained that transmission GSP upgrades are generally in large chunks, such as 240MW or 360MW, and that small capacity upgrades are quite rare. It was noted by a separate Working Group member that the respondent is quite active in Scotland and that, for Scottish GSPs, it is quite common for it to be a release of 5 to 125 years of firm capacity, and small increases in capacity had been seen.
- 6.35 The Working Group discussed whether option 2.1 should be developed further in light of the fact that a connecting customer, who did not trigger the works, would be liable for charges related to the creation of a new GSP (including small customers or a housing estate).
- 6.36 The Working Group discussed whether, for option 2.1 and in the event that only a single customer connects, this burdens other customers with unnecessary costs (e.g., through socialisation). A Working Group member suggested that it could be argued this is not unnecessary cost as it may defer the need for a GSP in another location.
- 6.37 The Working Group discussed that option 2.1 could result in any customers connecting to a GSP, including a domestic connection, being liable for costs related to the transmission work which is several voltage levels away from the connecting customer, whereas 2.2 puts in place a threshold (either voltage or capacity based) which prevents customers below being liable for those costs. It was noted that customers would still contribute to these through DUoS. The Working Group discussed that option 2.2 could be taken forward with varying options in setting a threshold (i.e., different levels) or different types of threshold (e.g., voltage or capacity). The Working Group discussed that the rationale around needing some form of threshold could justify option 2.1 not being taken forward, in favour of option 2.2 (or a number of variances of this option) being taken forward instead but noted that some consultation respondents may have misunderstood the way option 2.1 would work. For simplicity, it was agreed to progress both options 2.1 and 2.2 for consultation, and then eliminate option 2.1 after the second consultation if this was deemed appropriate
- 6.38 The Working Group concluded that the reasons for not taking forward options 1.3 and 1.4 applied to options 2.3 and 2.4, and that, as such, these options should also not be taken forward. However, in the course of Working Group discussions some felt that establishing a high-cost

threshold would serve to protect the wider charging base from additional unnecessary costs. As such, it was agreed to explore what an appropriate threshold would be.

- 6.39 A Working Group member observed that a high-cost project threshold would implicitly drive a lot of uncertainty. It was discussed that this may depend on the design of the high-cost threshold.

Question 6: Should any of the proposed solutions referenced in Question 5 not be taken forward? Please provide your rationale.

- 6.40 The Working Group discussed whether moving away from option 2.1 might be discriminatory, however it was discussed that under the existing arrangements, customers do not pay towards works that are performed two voltage levels higher than the voltage that they are connected at. It was discussed that these customers are so far removed from the voltage level of the works that they are in effect not benefitting from those works. It was noted that even if a customer does not pay up front for a portion of the works, they do pay towards this through their DUoS charges.
- 6.41 The Working Group discussed whether 2.1 leads to inconsistencies in application of charges to smaller scale connections, as opposed to option 2.2 (or a variation thereof) which would apply a threshold or lower limit on which connections charges apply to.
- 6.42 The Working Group debated whether there would be a risk to smaller users, such as housing developments, under option 2.1, as at least one Working Group member believed the ECCR would prevent charges applying to such customers under this option.
- 6.43 The Working Group discussed the potential impact on Scottish connections, where the threshold for triggering the works is lower (200kV on the mainland and 50kV on the islands), which would result in a lot of admin work due to capturing lots of miniscule proportions, which could prove to be cost and time prohibitive. It was discussed that the root cause of this issue would sit outside the scope of this CP.
- 6.44 As per Paragraph 6.37 above, it was agreed to progress option 2.1 and consult on this further, ensuring there were sufficient explainers in the next consultation about the limitations of this option (no threshold) and its consequences.
- 6.45 The Working Group debated whether option 2.4 should be progressed.
- 6.46 Some Working Group members felt the principle of option 2.4, a high-cost project threshold, which protects the broader charging base against costs for works they do not benefit from, was worth supporting and that such thresholds had already been implemented.
- 6.47 The Working Group debated the likelihood of the risk materialising where a small connection triggers a substantial amount of transmission reinforcement work, in a world of connections reform and the amount of strategic planning going on. Some Working Group members were of the view that, realistically, NESO would look at other options in such cases, and therefore the risk to the wider charging base should be small.
- 6.48 The Working Group acknowledged it may take some amount of effort to determine what that threshold should be and agreed to progress Option 2.4 in order to consider this further. The

Ofgem representative explained that, in general, a threshold could be supported (however this is not to be taken as a form of approval or steer from Ofgem.)

Question 7: Should the proposed alternative solution under option 3.1 be taken forward?

Please provide your rationale.

6.49 The Working Group noted four respondents supported taking option 3.1 forward.

6.50 The Working Group debated whether this option should be progressed. One Working Group member explained that option 3.1 improves upon the status quo by providing clarity that should result in more consistent application across DNOs and that, in the absence of Ofgem approving any of the other options, this would at least improve on the status quo.

6.51 The Working Group agreed to progress Option 3.1.

Question 8: What are the pros and cons of adopting an approach that causes no detriment to contracted customers? Please provide your rationale.

6.52 The Working Group noted the following 'pros' identified by consultation respondents:

6.52.1 causes no detriment to contracted customers;

6.52.2 maintains economic viability, especially where investment has already been made;

6.52.3 avoids the introduction of unexpected costs to customers who would otherwise be impacted;

6.52.4 prevent unnecessary delays by removing uncertainty;

6.52.5 prevents CP30 targets being jeopardised;

6.52.6 fairer on existing contracted projects;

6.52.7 prevents an increase in the cost of capital and subsequently higher electricity prices in the longer term;

6.52.8 prevents destabilisation of existing projects;

6.52.9 allows earlier implementation as it is unlikely DNOs will have the ability to add new costs to contracts;

6.52.10 it is fairer to connection customers as none are worse off; and

6.52.11 it could remove one of the main development risk factors for both our own projects and of those of our competition.

6.53 The Working Group noted the following 'cons' identified by consultation respondents:

6.53.1 socialisation/impacts on DUoS customers; and

6.53.2 it may result in two methodologies coexisting for a period of time, resulting in administrative burdens.

- 6.54 The Working Group noted that 8 respondents specifically expressed support for a 'no detriment' approach, noting that some of this support was conditional on additional clarification (more clarity and detail on what exactly is meant by 'existing contracted').
- 6.55 The Working Group noted the pros and cons, with considerably more pros than cons, and acknowledged the cons would need to be considered.
- 6.56 The Working Group noted the additional points raised are considerations for implementation (e.g., how to deal with gate 2 offers) for each of the options, the timing of the implementation, and which customers may or may not benefit. The Working Group agreed that the concerns raised will be used to test the solutions that are developed.
- 6.57 The Working Group discussed whether the no detriment approach can be met in all DNO areas, as some DNOs already recover costs via their price control. It was discussed that when considering implementation, if a customer is in an area that the DNO currently does recover these costs via their price control, contracted customers should not face additional costs as a result of the implementation of this CP. It was noted that the legal text, as currently drafted, does not yet contain provisions to prevent detriment and this will need iterating upon.

Question 9: Do you have any other comments?

- 6.58 The Working Group noted the concern expressed around user commitment and the underwriting that is sometimes needed. Whilst the Working Group may need to consider this for each of the options, it is out of scope of this Change Proposal to change this (and it would require a CUSC modification to be raised).
- 6.59 The Working Group discussed whether, if the costs are apportioned under any of the options, there be a scaling/apportionment of the security. It was explained that securities are for each individual customer and that they would be liable to pay this to NESO should they cancel.
- 6.60 The Working Group noted the request for more consideration as to how demand and generation connections share transmission assets and whether the solutions provide the best cost reflectivity for how transmission asset costs are shared between these. The Working Group agreed to review this against each of the options.
- 6.61 The Working Group noted the suggested to increase the cross-code collaboration between this CP and CMP460. The Working Group discussed that the current direction of travel for CMP460 was for full socialisation and that, if approved, it would make the DCUSA solutions superfluous, as no costs would be passed through. The Working Group also discussed that the solutions developed under this CP are not dependant on those developed under CMP460, and that it could not be taken as read that any of the solutions (under this CP or CMP460) would be approved. It was therefore agreed to continue with the development of the solutions under this CP.

Question 10: Do you consider that any of the options would significantly better facilitate the DCUSA Charging Objectives? Please give supporting reasons.

6.62 The Working Group noted that, broadly, there was a view that the solutions did better facilitate the DCUSA objectives. The Working Group noted, however, that the views were not granular enough to draw conclusions on each of the specific solutions being developed, and that views on each separate solution may need to be sought under consultation 2.

Question 11: Are you aware of any wider industry developments that may impact upon or be impacted by this CP?

6.63 The Working Group noted the following wider industry developments that it needs to be cognisant of:

6.63.1 CMP460;

6.63.2 ED3;

6.63.3 Connections Reform;

6.63.4 Clean Power 2030; and

6.63.5 Reforms to TNUoS as part of Reformed National Pricing.

6.64 One respondent highlighted CMP446, stating this removed Transmission Connection Asset charges for generators with an export capacity under 5MW. The respondent suggested that this precedent should be followed for any solutions implemented under DCP 461.

Question 12: Are you supportive of the proposal to implement the solution 5 Working Days after Authority approval?

6.65 The Working Group noted some support for a swift implementation; however, it was also noted that some of the responses expressed concern with this, such as:

6.65.1 not allowing enough time to ensure all relevant processes are updated;

6.65.2 not be long enough to communicate the change to customers so they understand the impact of any change;

6.65.3 not all DNOs have been funded in RIIO-ED2 for these costs, where the licence specifies that they must not be treated as direct pass-through;

6.65.4 any option (other than option 3.1) risks the cost burden falling on both the generality of customers and shareholders;

6.65.5 DNOs should charge in line with existing licence and code obligations until ED3;

6.65.6 option 3.1 also proposes minor licence modifications to ensure that costs are not recovered via both the Connection Charge and Use of System Charges;

6.65.7 that it is too soon to consider the implementation timeline without further detail of the solutions developed by this CP and CMP460;

- 6.65.8 that support for a swift implementation is conditional on a 'no detriment' approach being taken; and
 - 6.65.9 that due to the potential for an adopted change resulting in material financial implications and the interaction with DNO funding, any changes to the charging rules need to be implemented in unison with changes to allowances, whether through the ED3 determination or another approach such as a re-opener.
- 6.66 The Working Group discussed whether the concerns were about when the legal text was physically implemented into the DCUSA or when the legal text takes effect. It was discussed that, if a solution is approved, the legal text could either be implemented in a future DCUSA release (and would remain pending until then) or could be implemented in a sooner release and time-gated to go live at a preferential date. It was discussed that 1 April 2028 may be the desirable date for a solution to take effect.

Question 13: Do you have any comments on the commentary provided for the proposed legal text changes?

- 6.67 The Working Group noted that no comments had been provided on the legal text commentary.

7 Summary of Consultation 1 Working Group Conclusions & Next Steps

- 7.1 The Working Group concluded that the following options will be progressed:
- 7.1.1 option 1.1;
 - 7.1.2 option 1.2;
 - 7.1.3 option 1.1, with option 1.4
 - 7.1.4 option 1.2, with option 1.4
 - 7.1.5 option 2.1;
 - 7.1.6 option 2.2;
 - 7.1.7 option 2.1, with option 2.4
 - 7.1.8 option 2.2, with option 2.4 and
 - 7.1.9 option 3.1.
- 7.2 The legal text for these solutions can be found in section 2 below. The solutions have not materially changed following the completion of the consultation 1 responses.
- 7.3 The Working Group acknowledged that Ofgem may request additional analysis during the decision or send back stage.
- 7.4 The Working Group concluded that the following options will not be progressed:
- 7.4.1 option 1.3; and

7.4.2 option 2.3.

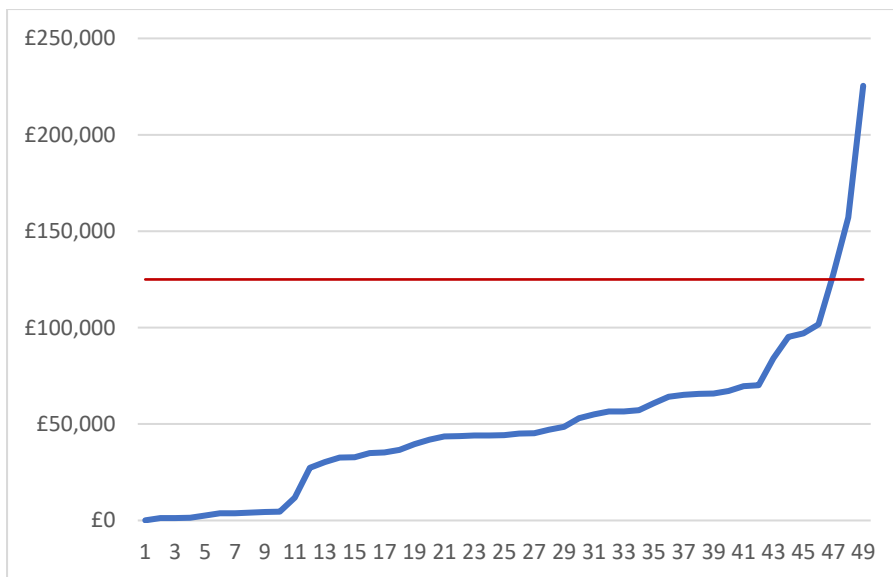
7.5 The Working Group identified the following further development work needed ahead of Consultation 2:

- Determine the High-Cost Project Cap Threshold
- Consider cost apportionment with applicability criteria (capacity based vs voltage based thresholds)
- Consider no detriment approach
- Consider ECCR interactions

8 Consultation 2 Working Group Assessment

High-Cost Project Cap Threshold

- 8.1 The working group considered potential means of determining an appropriate High-Cost Project Threshold. The Working Group noted the approach used by Ofgem to determine the High-Cost project threshold as part of Access SCR, which was based on offers issued by DNOs over the course of RIIO-ED1, recalling that the data showed the percentile where cost of the reinforcement increased exponentially. The Working Group discussed that a similar analysis may reveal the appropriate percentile to use.
- 8.2 The Working Group analysed a range of historic transmission reinforcement costs, provided by NESO and NGET, to determine where typical project costs end and where exceptional, highly-priced schemes begin (see Attachment 5). When the group analysed the sorted cost-per-MW curve, they saw that most projects followed the same steady pattern, with costs increasing gradually. However, once they reached the top end of the curve, there was a clear point where the numbers suddenly jumped far higher. This sharp rise occurred around the £100,000–£125,000 per MW mark, which also aligns closely with the 95th percentile of the data. The working group considered that a HCPT of £125,000 per MW would be appropriate.



Extract from Attachment 5

8.3 By adopting a threshold at this level, the methodology ensures that the vast majority of projects are treated consistently, while allowing unusually expensive, outlier schemes to be identified transparently and treated appropriately.

8.4 Attachment 7 provides some illustrative examples demonstrating how the HCPT would operate under the proposed solution variants. For the purposes of the examples, the HCPT is set at £125,000/MW, with the threshold for each connection calculated as the customer's requested capacity multiplied by this value.

Question 1: Do you agree with the Working Group's approach (as previously applied by Ofgem in other methodologies) is the appropriate method for determining a High Cost Project Threshold? Please explain your reasoning.

Question 2: Do you agree with the working groups position of applying a HCPT of £125,000 per MW. Please provide your rationale either way.

Option 2.2 – Cost Apportionment with Applicability Criteria (Capacity based vs Voltage based Thresholds)

8.5 To ensure that cost apportionment applies only to customers whose connections materially contribute to transmission-level reinforcement, the Working Group considered two alternative approaches for defining an applicability threshold:

a) Capacity-based threshold (e.g., 5 MW)

8.6 Under this approach, only connections requesting capacity above a defined MW threshold would be exposed to transmission-related cost apportionment.

- For England & Wales, this aligns broadly with thresholds for Transmission Evaluation Assessments (typically 1 MW or 5 MW depending on the GSP).

- This approach ensures that domestic and small commercial customers, whose contributions to transmission loading are minimal, are not subject to these charges.
- The main advantage with this approach is that the customer would generally know in advance whether they could be exposed to the charges or not but the exposure would vary by the GSP being connected to as the TEA thresholds vary.

b) Voltage-based threshold

- 8.7 Here, exposure to transmission-related costs is determined by the voltage at which the customer connects. So only customer connecting at EHV and above would be exposed to the costs. This uses a similar principle to the two voltage rule but applied the other way such that only 132kV and EHV are exposed to the charges but voltages that are more than two voltage levels away are not. The main disadvantage is that customers would not always know when they apply what voltage they would connect to.
- 8.8 Both approaches have merits: capacity thresholds are simple and intuitive; voltage thresholds provide stronger alignment with existing charging principles and engineering boundaries. The Working Group invites views on which approach stakeholders prefer.

Question 3: Do you agree that a 5 MW threshold is appropriate for identifying when assets should be subject to cost apportionment under Option 2.2? If not, do you prefer an approach based on voltage level? Please provide justification.

No Detriment Approach

- 8.9 Attachment 6 sets out how different DCP 461 solution options would apply to customers depending on their connection status and the stage of their connection offer. It compares each option against three broad customer groups: already connected, contracted but not yet connected (with three sub-categories of Gate 2 status), and not yet contracted.
- 8.10 Across all options, the assessment focuses on *avoiding detriment* as the industry transitions to new cost-treatment arrangements. The document shows, for each option:
- Whether existing or contracted customers would see no change, a revision to their offer, or need for a distribution variation, depending on whether any transmission-related charges had previously been included.
 - How the introduction of a HCPT changes the treatment—i.e., customers below the threshold receive the new, more favourable approach, whereas customers above the threshold retain existing charging positions.
 - How different models (No Transmission Cost Pass-Through, Cost Apportionment, and Applicability-Based Cost Apportionment) impact customers depending on their timing and circumstances.
 - That “already connected” customers consistently face no retrospective change across all options.
 - That “not yet contracted” customers consistently receive offers based on the new arrangements from go-live onwards.

Question 4: Do you agree with the working groups proposed no detriment approach? Please provide your rationale either way.

Standardised approach

Option 3.1 – DNO Parties apply a consistent locational signal – no DUoS impact

- 8.11 The Working Group noted that this option was not applicable to scenarios where the customer had contracted but not yet connected.
- 8.12 The Working Group agreed that applications received after the implementation date would have full costs in their offers.

ECCR Consideration

- 8.13 The Working Group explored how the ECCR² interacts with the proposals under DCP 461. This Working Group noted that the ECCR governs how first-comer and later-comer customers share the costs of reinforcement assets, which are rules that continue to apply even when changes are made to how connection charges are calculated.
- 8.14 The Working Group discussed that even though assets may sit on the transmission network (e.g., supergrid transformers), the ECCR applies as soon as these costs form part of a DNO connection offer. This means customers connecting later may still need to reimburse earlier customers under the ECCR. For example, if a solution removes charges from initial customers, the ECCR can still require later customers to make proportional contributions to earlier customers' costs.
- 8.15 The Working Group agreed that the impact of the ECCR should be assessed against each of the options.
- **Options 1.1, 1.4, 2.1 and 2.2:** ECCR has **no material impact**, as costs are either not passed through or apportioned.
 - **Option 3.1:** ECCR *could* mitigate last remaining customer risk by allowing reimbursement if later connectees share assets.
 - **Option 1.2:** where a single customer triggers the need for a dedicated GSP, no ECCR reimbursement would apply. This reflects established ECCR practice under which a customer choosing a bespoke solution does not receive later rebates, preventing cross customer distortions.
- 8.16 There will be no change to the existing treatment of ECCR. Reinforcement charges for transmission reinforcement will be apportioned to either demand and/or generation customers

² [https://www.energynetworks.org/assets/images/Publications/2024/241219-ena-electricity-\(connection-charges\)-regulations-guidance-v3.0.pdf?1734804763](https://www.energynetworks.org/assets/images/Publications/2024/241219-ena-electricity-(connection-charges)-regulations-guidance-v3.0.pdf?1734804763)

depending on the agreed capacity released by the reinforcement works for demand and/or generation customers.

9 Summary of Solutions

- 9.1 This section provides a high-level summary of the nine proposed solution variants being consulted on.
- 9.2 **Option 1.1 - No transmission reinforcement costs passed through:** where a Distribution connection triggers transmission reinforcement at a Connection Site, the DNO would not pass those transmission reinforcement costs to the connecting customer; instead, the costs would be recovered from the wider DUoS charging base.
- 9.3 **Option 1.2 - Option 1.1 with an exception for a single-customer GSP:** the same approach as Option 1.1, except that where a new/dedicated GSP is created wholly or mainly for a single customer, that customer would continue to pay the relevant transmission reinforcement costs (reflecting sole-use principles).
- 9.4 **Option 1.1 + 1.4 - Option 1.1 with a High-Cost Project Threshold (HCPT):** Option 1.1 would apply for most projects, but exceptionally high-cost transmission reinforcement projects (above the HCPT) would remain chargeable to the connecting customer (so DUoS customers are protected from outlier costs and some locational signal is retained for extremes).
- 9.5 **Option 1.2 + 1.4 - Option 1.2 with a HCPT:** Option 1.2 would apply for most projects, but where transmission reinforcement costs are above the HCPT, the relevant costs would be charged to the connecting customer in line with the HCPT design.
- 9.6 **Option 2.1 - Cost apportionment:** instead of one customer (or the last remaining customer) potentially paying all transmission reinforcement costs, each in-scope connecting customer would pay only an apportioned share of the costs, with the remainder initially recovered from the wider DUoS charging base and subsequently apportioned to any other customer connecting.
- 9.7 **Option 2.2 - Cost apportionment with applicability criteria:** Option 2.1, but with an additional threshold/criterion to define which connections are in scope for paying an apportioned share (for example, based on capacity such as 5 MW, or based on voltage). This is intended to avoid very small connections being exposed to transmission-level costs.
- 9.8 **Option 2.1 + 2.4 - Option 2.1 with a HCPT:** Option 2.1 would apply for most projects, but where transmission reinforcement costs are above the HCPT, the relevant costs would be charged to the connecting customer(s) in line with the HCPT design.
- 9.9 **Option 2.2 + 2.4 - Option 2.2 with a HCPT:** Option 2.2 would apply for most projects, but where transmission reinforcement costs are above the HCPT, the relevant costs would be charged to the connecting customer(s) in line with the HCPT design.
- 9.10 **Option 3.1 - Standardised approach (status quo, but clarified):** the DNO would recover the relevant transmission reinforcement costs from the connecting customer(s) (i.e., no DUoS

socialisation), but the DCUSA drafting would be clarified to drive a more consistent approach across DNOs, including reflecting interaction with ECCR (and any necessary licence drafting would be progressed in parallel).

Question 5: For each of the nine proposed solution variants summarised above, please indicate whether you would like the Working Group to take it forward for Authority consideration or not take it forward (i.e., eliminate it), and, if you have one, indicate your preferred option. A simple table for recording your selections is provided in the Consultation 2 Response Form (Attachment 2).

10 Legal Text Commentary

10.1 The legal text developed for each option can be found in Attachment 1.

10.2 The below commentary provides an overview of the amendments made to the legal text. The paragraph numbers relate to those paragraphs under Schedule 22 of the DCUSA which have been added or amended.

Option 1.1

10.3 Amends Schedule 22 paragraph 1.73 so ISOP charges for GB Transmission System works are not reflected in the customer's Connection Charge.

Option 1.2

10.4 Amends Schedule 22 paragraph 1.73 so ISOP charges for GB Transmission System works are reflected in the customer's Connection Charge where the transmission works are required exclusively for their use, otherwise no charge for this work will be made to them.

Option 1.1 + 1.4

10.5 As option 1.1 but a HCPT applies.

Option 1.2 + 1.4

10.6 As option 1.2 but a HCPT applies.

Option 2.1

10.7 Amends Schedule 22 paragraph 1.34 to include references to GB Transmission System assets (for ECCR/previous works recovery).

- Amends Schedule 22 paragraph 1.73 so ISOP charges for GB Transmission System works are apportioned between the DNO and the customer.
- Adds new paragraphs 1.74–1.79 to define and apply Cost Apportionment Factors (Transmission Security CAF and Transmission Fault Level CAF), including definitions and how the factors apply (e.g., for augmentations and interactions between rules).
- Renumbers existing paragraphs following the insertion of the new provisions.

Option 2.2

10.8 Amends Schedule 22 paragraph 1.34 to include references to GB Transmission System assets and to introduce an applicability threshold (e.g., capacity or voltage) to determine when payments/cost apportionment apply.

- Amends Schedule 22 paragraph 1.73 so ISOP charges for GB Transmission System works are apportioned between the DNO and the customer (where in scope).
- Adds new paragraphs 1.74–1.79 to define and apply Cost Apportionment Factors (Transmission Security CAF and Transmission Fault Level CAF), including definitions and how the factors apply.
- Renumbers existing paragraphs following the insertion of the new provisions.

Option 2.1 + 2.4

- Includes all amendments under Option 2.1 (cost apportionment drafting, including new Cost Apportionment Factor provisions and related renumbering).
- Adds a Transmission HCPT so that, above the threshold, relevant ISOP charges are payable in full as a Connection Charge (i.e., HCPT overrides the apportionment approach for outlier/high-cost cases).
- Updates paragraph numbering to accommodate the inserted HCPT provisions.

Option 2.2 + 2.4

- Includes all amendments under Option 2.2 (cost apportionment drafting with an applicability threshold/criteria, plus the new Cost Apportionment Factor provisions and related renumbering).
- Adds a Transmission HCPT so that, above the threshold, relevant ISOP charges are payable in full as a Connection Charge (i.e., HCPT overrides the apportionment approach for outlier/high-cost cases).
- Updates paragraph numbering to accommodate the inserted HCPT provisions.

Option 3.1

10.9 Amends Schedule 22 paragraph 1.73 so ‘Relevant Charges’ are reflected in the customer’s Connection Charge.

- Updates the Schedule 22 glossary (Section 2) to add a definition of ‘Relevant Charges’.
- Identifies associated changes needed to Electricity Distribution Licence Special Condition 1.1 (definitions of Transmission Connection Point Charges and New Transmission Capacity Charges) to align with the revised charging treatment.

Question 6: Do you have any comments on the proposed legal text changes for each solution?

11 Relevant Objectives

Assessment Against the DCUSA Objectives

11.1 For a DCUSA Change Proposal to be approved it must be demonstrated that it better facilitates the DCUSA Objectives. This CP is being assessed against the DCUSA Charging Objectives.

DCUSA Charging Objectives	Header	Header	Header
	1	2	3
1. That compliance by each DNO Party with the Charging Methodologies facilitates the discharge by the DNO Party of the obligations imposed on it under the Act and by its Distribution Licence	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>
2. That compliance by each DNO Party with the Charging Methodologies facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector (as defined in the Distribution Licences)	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>
3. That compliance by each DNO Party with the Charging Methodologies results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the DNO Party in its Distribution Business	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>
4. That, so far as is consistent with Clauses 3.2.1 to 3.2.3, the Charging Methodologies, so far as is reasonably practicable, properly take account of developments in each DNO Party's Distribution Business	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input type="checkbox"/>
5. That compliance by each DNO Party with the Charging Methodologies facilitates compliance with the EU Internal Market Regulation and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators; and	<input type="checkbox"/>	<input type="checkbox"/>	<input type="checkbox"/>
6. That compliance with the Charging Methodologies promotes efficiency in its own implementation and administration.	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>	<input checked="" type="checkbox"/>

Options 1.1, 1.2, 1.1 with 1.4 and 1.2 with 1.4

11.2 These options remove a charging anomaly and ensures more consistent outcomes for customers. It therefore has a positive impact in terms of competition and avoiding discriminations and promoting more efficient use of the network. It ensures consistency of charging outcome for customers irrespective of the categorisation of the GSP they are connected to. It also ensures consistent of outcome across DNOs irrespective of whether DNOs have been funded for transmission work in their price control. The charge removes the need for complex charging arrangements and making changes to connection offers if the number of contracted customers at a GSP changes which has a positive impact on objective 6.

Options 2.1, 2.2, 2.1 with 2.4 and 2.2 with 2.4

11.3 It is believed that DCSUA Charging Objectives 1, 2, 3, 4 and 6 will be better facilitated by improving consistency in charging between different regions and reducing the risk of a variable and unsustainable financial burden on Individual Customers. This would ensure consumers

experiences are consistent regardless of the location of the connection and ensuring no specific region is more attractive than another for a connection of the same type. Charging experienced by customer will be more proportionate.

Option 3.1

11.4 It is believed that DCUSA Charging Objectives 2 and 6 will be better facilitated by this option, with all others having a neutral impact. This would be courtesy of the consistent application of the charging methodologies through simple amendments to existing DCUSA provisions. This should ensure that competition is not affected (and where it is the application of the CUSC charging methodology which is creating a perceived defect and should therefore be addressed at its root cause).

Question 7: Having now seen the developed solutions and legal text, do you consider that any of the options would better facilitate the DCUSA Charging Objectives? Please specify which options better facilitate which objectives and give supporting reasons.

12 Impacts & Other Considerations

Does this Change Proposal impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

12.1 Consideration may be needed for potential DUoS SCR impacts.

Consumer Impacts

12.2 It is anticipated that the connection costs for in scope consumers will be reduced, however depending on the solution taken forwards this may result in costs being socialised across other consumers.

12.3 The challenges around performing an impact assessment are described in paragraphs 5.45 to 5.49, earlier in this document.

Environmental Impacts

12.4 In accordance with DCUSA Clause 11.14.6, the Working Group assessed whether there would be a material impact on greenhouse gas emissions if this CP was implemented. The Working Group did not identify any material impact on greenhouse gas emissions from the implementation of this CP.

Question 8: Are you aware of any wider industry developments that may impact upon or be impacted by this CP?

12.5 It is proposed that, for Options 1.1, 1.2, 1.4, 2.1, 2.2 and 2.4 that Implementation Date should be one month after Ofgem's decision and that this would also be the 'Go Live' date.

12.6 With respect to Option 3.1 it is proposed that the Implementation Date should be 01 April 2028 (which aligns to the start of the RIIO ED3 price control period).

Question 9: Are you supportive of the proposed implementation dates for the solutions?

13 Consultation Questions

13.1 The Working Group is seeking industry views on the following consultation questions:

No.	Questions
1	Do you agree with the Working Group's approach (as previously applied by Ofgem in other methodologies) is the appropriate method for determining a High Cost Project Threshold? Please explain your reasoning.
2	Do you agree with the working groups position of applying a HCPT of £125,000 per MW. Please provide your rationale either way.
3	Do you agree that a 5 MW threshold is appropriate for identifying when assets should be subject to cost apportionment under Option 2.2? If not, do you prefer an approach based on voltage level? Please provide justification.
4	Do you agree with the working groups proposed no detriment approach? Please provide your rationale either way.
5	For each of the nine proposed solution variants summarised above, please indicate whether you would like the Working Group to take it forward for Authority consideration or not take it forward (i.e., eliminate it), and, if you have one, indicate your preferred option. A simple table for recording your selections is provided in the Consultation 2 Response Form (Attachment 2).
6	Do you have any comments on the proposed legal text changes for each solution?
7	Having now seen the developed solutions and legal text, do you consider that any of the options would better facilitate the DCUSA Charging Objectives? Please specify which options better facilitate which objectives and give supporting reasons.
8	Are you aware of any wider industry developments that may impact upon or be impacted by this CP?
9	Are you supportive of the proposed implementation dates for the solutions?
10	Any other comments?

13.2 Responses should be submitted using Attachment 2 to dcusa@electralink.co.uk by no later than **29 May 2026**.

13.3 Responses, or any part thereof, can be provided in confidence. Parties are required to clearly indicate any parts of a response that are to be treated confidentially.

14 Attachments

- Attachment 1 - DCP 461 Draft Legal Text
- Attachment 2 - DCP 461 Consultation 2 Response Form
- Attachment 3 - Cost Apportionment Factor
- Attachment 4 - DCP 461 Consultation 1 Responses and Feedback
- Attachment 5 - DCP 461 Anonymised Dataset Summary
- Attachment 6 - DCP 461 No Detriment Approach Assessment
- Attachment 7 - Illustration of HCPT for Options 1 and 2
- Attachment 8 - DCP 461 Change Proposal Form