





DCUSA Change Declaration		At what stage is this document in the process?
<h1>DCP 392:</h1> <h2>Charging of Third Party DNO Works to Transmission Connection Users</h2> <p><i>Raised on the 12 July 2021 as a Standard Change</i></p>	01 – Change Proposal	
	02 – Consultation	
	03 – Change Report	
	04 – Change Declaration	
<p>Purpose of Change Proposal:</p> <p>DCP 392 seeks to apply some of the principles of the Common Connection Charging Methodology (CCCM) to transmission connections that trigger works on a distribution system, and to apply the equivalent of the Electricity (Connection Charges) Regulations (ECCR) for reimbursement to the transmission-connected customer where Cost Apportionment Factor (CAF) rules do not currently apply. At present, a customer with an accepted transmission offer or a transmission connected site pays the full charge for any distribution works triggered by their connection.</p>		
	<p>DCUSA Parties have voted on DCUSA Change Proposal (DCP) 392 with the outcome being a recommendation to the Authority as to whether or not the Change Proposal (CP) should be accepted. As DCP 392 is considered to be a Part 1 Matter, the recommendation will be issued to the Authority for their final decision.</p> <p>The DCUSA Parties consolidated votes are provided as Attachment 2.</p>	
	<p>For DCP 392, DCUSA Parties recommend to the Authority to:</p> <ul style="list-style-type: none">• Reject the proposed variation (solution); and• Reject the implementation date.	
	<p>DCUSA Parties Impacted: DNO and IDNO Parties.</p> <p>Other: Generators (including storage and any other transmission users impacting the distribution system)</p>	
	<p>Impacted Clauses: A new Schedule</p>	

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Any questions?

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Timetable

The timetable for the progression of the CP is as follows:

Change Proposal timetable

Activity	Date
Initial Assessment Report Approved by Panel	21 July 2021
Consultation issued to Parties	21 March 2022
Change Report issued to Panel	14 September 2022
Change Report issued for Voting	23 September 2022
Party Voting Ends	14 October 2022
Change Declaration Issued to Parties	18 October 2022
Authority Decision	TBC
Implementation	01 April 2023

a false and inefficient incentive to connect at the distribution voltage nearby, where the works could be the same but charged differently.

How?

- 1.7 The proposed change will apply the principles of CCCM to the costs of the distribution system works for transmission users who trigger distribution works relating to a transmission connection. This will allow the full cost of Reinforcement works to be apportioned based on the proportion of thermal capacity or fault level headroom used by the new customer.
- 1.8 Additionally, this change proposes that the principles of the ECCR² will apply for any further modifications or new connections to the transmission system that utilises the distribution assets installed for the initial request.

2 Governance

Justification for Part 1 Matter

- 2.1 The change proposal has been designated as a “Part 1” matter as it satisfies one or more of the following criteria:
 - a) it is likely to have a significant impact on the interests of electricity consumers;
 - b) it is likely to have a significant impact on competition in one or more of:
 - i. the generation of electricity;
 - ii. the distribution of electricity;
 - iii. the supply of electricity; and
 - iv. any commercial activities connected with the generation, distribution, or supply of electricity
 - c) it is likely to discriminate in its effects between one Party (or class of Parties) and another Party (or class of Parties);
- 2.2 It is the proposers’ opinion that the current mechanism, which charges 100% of DNO works to the impacting transmission connection user, is anticompetitive for transmission connection users in relation to upfront capital costs and this must be rectified to ensure the distribution charging methodology no longer discriminates against one class of Parties.

² The basis of solution proposed has been based on the Electricity (Connection Charges) Regulations 2017, but the Working Group note that this is under review (see paragraphs 3.8 and 3.9 below).

Next Steps

- 2.3 DCUSA Parties have voted and the outcome of the Party vote acts as a recommendation to the Authority as to whether this CP should be accepted or not. Parties recommend that DCP 392 should not be accepted and therefore, that the change should not be made.

3 Why Change?

Background of DCP 392

- 3.1 There is a current modification to the CUSC, CMP328³, which proposes to put in place an appropriate process to be utilised when any transmission connection triggers work on the distribution system.
- 3.2 CMP328 was raised by SSEN to challenge the utilisation of the Third-Party Works process proposed by NGESO in situations where a transmission connected project might trigger works on the distribution network. CMP328 proposes the implementation of a Distribution Impact Assessment process which would establish NETSO as the DNO's customer and require them to make an application on behalf of their customer. This application would trigger an assessment which will allow the DNO to assess the impact of connection; provide a quotation for works required and update any enduring requirements in the contractual arrangements held between NETSO and the DNO. The charging strategy for any works triggered (and several other wider issues) was agreed by the CUSC Working Group as not in scope for CMP328.
- 3.3 It is expected that a decision by the Authority on CMP328 is likely to be made in November 2022.
- 3.4 The proposer is suggesting that the Cost apportionment approach⁴, as set out in the CCCM, needs to be adopted in respect of costs for the DNO works required to facilitate connections to the transmission system. Currently the CCCM, pursuant to s16 the Electricity Act 1989 and in accordance with the provisions of the distribution licence conditions 12 and 13, only applies to connections to the distribution system.
- 3.5 The approach suggested by the proposer would equalise the playing field in relation to upfront capital costs between distribution and transmission connected assets and remove disproportionate distribution connection charges currently levied on impacting transmission users. Two examples of such disproportionate costs are highlighted in the change proposal are shown below:

Live Project 1 – an example

- 49.9 MW 13 kV tertiary connected battery scheme at a southern GSP.

³ [CMP328: Connections Triggering Distribution Impact Assessment | National Grid ESO](#)

⁴ The costs of the re-enforcement will be apportioned dependent upon two cost apportionment factors, one being the security of supply and the other the fault level (paragraph 1.16-1.28 of Schedule 22)

- DNO proposes to upgrade the CBs to 40 kA rating at a cost of £3.83M, fully funded by the triggering party.
- 1x distribution CB increases to 96.5% of its asymmetrical break limit (29.34 kA) so must be replaced. Customer contribution is 0.54 kA.
- A further 8x CBs are pushed out of their single and three phase fault ratings (27 kA). Single phase rating is breached first. Customer contribution is 0.21 kA. These 8 CBs are already operating at 99.8% of their rating before our connection.
- A further 1x CB is being replaced anyway under a capital scheme.
- DNO did not have capital funding to replace other stressed breakers that needed replacing anyway. Transmission customer will provide this funding for their benefit.
- Assuming all CBs are evenly priced, the 8x CBs should cost £3.40M. Fault level CAF = $3 \times (0.21/40) \times 100 = 1.6\%$
- Under CAF, customer contribution would be £54,471.
- For the first CB, fault level CAF = $3 \times (0.54/40) \times 100 = 4.1\%$.
- Under CAF, customer contribution would be £17,448.
- If project was distribution connected, customer could contribute £71,919 under the CAF mechanism, with the remainder being covered by the DNO and socialised across subsequent customers.
- Presently, the transmission customer is facing an effective £3.79M penalty for opting for a transmission connection. This is anti-competitive and could result in cancellation of the project on economic viability grounds.

Live Project 2

- 49.9 MW 13 kV tertiary connected solar and storage scheme at a south western GSP.
- DNO's third party works assessment highlighted widespread thermal constraints.
- Mitigation required 30.5km of 132 kV reinforcement.
- Cost £17.7M. If CAF was applied, cost would be approx. £10.4M taking into account the £200/kW high-cost reinforcement cap.
- This is an approx. £7.3M over-spend by the transmission user for the DNO's benefit.
- Active, enduring solutions technically possible but this is currently outside the contractual scope of the third party works process. Something CMP328 is considering.
- To date, no options have been pursued and the project is at real risk of cancellation.

3.6 The Working Group discussed the potential for other distortions for opting for a connection at either the transmission or distribution level but noted that this change proposal is seeking solely to address the difference of upfront capital costs and so other potential differences are not considered further within this change proposal.

- 3.7 In addition, any future connections or modifications made to either the transmission or distribution systems that benefit from the initial changes should follow the principles of the ECCR. The approach being suggested is wider than the scope of the ECCR which, being prescribed by s19 and Schedule 5B of the Electricity Act, only considers connections to the distribution system (not connections to the transmission system). The proposer is of the view that both types should be considered irrespective of whether the connection is to the distribution or transmission system.
- 3.8 It is understood that the Department for Business, Energy & Industrial Strategy (BEIS) has conducted a statutory Post Implementation Review (PIR) of The Electricity (Connection Charges) Regulations 2017 which came into force on 6 April 2017. BEIS has published a survey⁵ to collect information from stakeholders to help the assessment of:
- the extent to which the Regulations' objectives are being achieved;
 - whether those objectives remain appropriate; and
 - if those objectives remain appropriate, the extent to which they could be achieved with less onerous regulatory provision.
- 3.9 The deadline for participating in the survey was 21 January 2022 and is now closed. The PIR was published in March 2022⁶. An extract of the executive summary stated:
- "This PIR has shown that ECCR 2017 have broadly performed as expected, but their regulatory context is changing independently of this. Ofgem has proposed to change the way connection costs are divided between billpayers and the connecting customer. These developments have triggered an evaluation of possible adjustments to ECCR 2017, which is scheduled to conclude in late 2022, and which BEIS will undertake in close cooperation with Ofgem and industry"*

4 Working Group Assessment

DCP 392 Working Group Assessment

- 4.1 The DCUSA Panel established a Working Group to assess DCP 392. This Working Group consists of Suppliers, Generators, developers, DNOs, IDNOs, Electricity Systems Operator (ESO) and Ofgem representatives. Meetings were held in open session and the minutes and papers of each meeting are available on the DCUSA website – www.dcusa.co.uk.

Challenge on the legal framework in which DCP 392 best sits

- 4.2 Prior to starting the process of refining and developing the solution for DCP 392, the Working Group considered a challenge that had been raised by a DCUSA Party related to whether the DCUSA was the

⁵ The survey document is available at https://beis.fra1.qualtrics.com/jfe/form/SV_9F7LETYTrhmYipw

⁶ [Post-Implementation Review of the Electricity \(Connection Charges\) Regulations 2017 \(legislation.gov.uk\)](https://www.legislation.gov.uk/uksi/2017/1000/contents/made)

most appropriate regulatory vehicle to incorporate such changes into. The Working Group discussed the proposed approach to amend the CCCM to cater for transmission connection. One member indicated that this cannot be catered for under the Licence or via the DCUSA since the CCCM is for connections to the distribution network. It was noted that the challenge had been raised via an email received by the DCUSA Code Administrator, which set out one Party's concerns and which had been raised prior to the Working Group being fully established.

4.3 During the Working Group's discussions on the topic of the most appropriate regulatory vehicle to incorporate such changes into, one Working Group member expressed their doubts that such a change could be considered a DCUSA matter and that DCP 392 falls outside of the scope of the CCCM and the DCUSA with the issues principally about:

- The relationship between the relevant ESO and the party seeking connection to the transmission system;
- How the transmission company passes on costs that arise as a consequence of having to modify its connection arrangements to a third party (in this case a DNO); and
- Where, as a consequence, the transmission operator requires the third party to modify its distribution assets to facilitate the connection to the transmission system.

4.4 The Working Group member expressed the opinion that they did not understand the logic that DNOs, and consumers connected to DNOs should be liable to costs of modifying the existing DNO connection assets where such works arise as a consequence of facilitating the connection of a party to the transmission system. Further, they saw the circumstances falling outside the scope of sections 16 to 23 of the Act and sections 12 to 15A of the electricity distribution licence.

4.5 This was discussed by the Working Group and a request for clarity from the legal advisors was obtained.

"My current understanding of the CUSC proposals is that NGESO will act as an interface between the T-connectee and the DNO/IDNO, that the T-connectee will be paying NGESO under the CUSC, and that any rebate will be paid by NGESO to T-connectee under the CUSC.

However, the CUSC modification will not be dealing with the charging methodology used by distributors to calculate charges for these reconfiguration works. The CUSC WG has taken the view that this is not within the CUSC vires. I agree with that.

The WG member⁷ still didn't seem quite convinced that the charging methodology for distribution reconfiguration works was within the vires of DCUSA, but he was going to consider further.

I remain of the view that this Change can be dealt with in the DCUSA. The scope of the Change would now seem to be setting out rules on how distributors charge for reconfiguration/diversion works (and similar) - possibly only when required by NGESO under the CUSC (but potentially more widely). Although

⁷ The WG member refers to the person who raised the issue and also replaces the name of the individual from the actual legal response

this is clearly not a distribution connection charging issue, I remain of the view that this can be dealt with in the DCUSA, and that the DCUSA is the most sensible home for distribution charging rules.”

- 4.6 Gowling WLG acknowledge that DCP 392 falls outside of the scope of the CCCM and they also acknowledge the challenges around the ECCRs referred to in paragraph 3.7. However, Gowling WLG recognise the position of the party seeking to raise the change, who have been advised (by CUSC representatives) that such change falls outside the provisions of CUSC, and that given the absence of a clear place for such arrangements, their formal view is that such provisions could be covered by DCUSA.
- 4.7 The Working Group agreed that:
- the legal response supported the progression of the change proposal; and
 - a separate schedule would be appropriate to make it clear that it is not part of the CCCM, although the elements of the CCCM could be used in drafting the schedule.
- 4.8 Prior to considering the solution, the Working Group undertook two requests for information to understand the current process.

RFI 1

- 4.9 The first RFI sought views from both DNOs and NGESO regarding the current arrangements related to reimbursement of reinforcement costs as well as costs associated with diversionary works across both distribution and transmission. The questions asked as part of the first RFI, alongside a summary of the responses received to the RFI are shown below. The document capturing the detailed responses, acts as Attachment 3 to this document.

Q1 - What are your current reimbursement arrangements where a distribution user pays for transmission reinforcement (as per DCUSA Schedule 22, Clause 1.43 to 1.44A)?

- 4.10 The majority of the responders stated that any transmission costs are charged to the distributor who then pass these on to the customer requesting the connection.
- 4.11 The NGESO response stated that they contract with industry parties for connections to the transmission system and connections to the distribution system which impact on the transmission system. They highlighted the CUSC process associated with pre and post connection.

Q2 - How are diversions catered for in the Distribution Licence regarding the costs incurred?

- 4.12 Some of the responders stated that any costs incurred as a result of diversionary works are treated in accordance with Charge Restriction Condition 5 (CRC5). Another stated that full costs would be charged. The NGESO stated that they don't hold a distribution licence, so the question is not relevant.
- 4.13 The responses were in line with the current process and expectations of the Working Group although a more focussed question was still required.
- 4.14 The Working Group discussed the following statement within the change proposal:

“It should be noted that some DNO areas are aligning Third Party Works cost apportionment with CCCM methodology already. This modification seeks to formalise the arrangement as described below and to ensure consistency amongst DNOs”

- 4.15 The Working Group decided that a further RFI was required to draw out whether the statement in paragraph 4.14 is already being applied by distributors.

RFI 2

- 4.16 The questions asked as part of the second RFI, alongside a summary of the responses received to the RFI are shown below. The document capturing the detailed responses, acts as Attachment 4 to this document.

Q1 - How do Distributors calculate charges for a transmission connected Customer that has an impact on the distribution system? An example would be a transmission connection to a tertiary winding that trigger works on the distribution system.

- 4.17 The responses were mixed, but those that did reference charges stated that these would be charged in full to the transmission connected customer.

Q2 - What methodology do you use to determine what costs should be charged?

- 4.18 One responder stated that there is no specific methodology but would charge the costs in full as no mechanism for cost apportionment applies. Another quoted the obligations within CRC5C, and others stated the full costs would be applied.

Q3 - Please provide justification for your charging arrangements, be that apportioning or charging in full.

- 4.19 The responders stated that there is no mechanism for cost apportionment and therefore they would charge in the costs in full.
- 4.20 The Working Group noted the response that cost apportionment is not currently applied to costs for works on the distribution system that are triggered by a transmission connection.

DCP 392 Solution Development

Recovery of costs process

- 4.21 The Working Group considered what regulatory framework was in place to enable distributors to be able to undertake investment for works triggered by transmission connections. The Working Group engaged with Ofgem and DNOs to understand whether there were existing mechanisms in place to allow distributors to recover costs incurred through the price control.
- 4.22 Despite this engagement the Working Group was unable to ascertain whether DNOs would be able to recover costs incurred for works triggered by transmission connections through use of DUoS rather than directly from the transmission customer as is the current practice and sought industry views as to whether this cost recovery is permissible.

Proposed Solution

- 4.23 In line with paragraph 4.7 the Working Group developed a separate schedule to be added into the DCUSA to cater for a transmission related distribution reinforcement methodology.
- 4.24 The schedule covers

- the initial request,
- where the full cost of the connection or Modification is made;
- the approach to applying CAF based on the rules similar to those in the CCCM; and
- how costs can be recovered and passed on to the initial payer based on the principles of the ECCR.

Costs to be paid in full

4.25 The schedule identifies areas where the transmission customer will be expected to pay in full. These include:

- Extension Assets;
- additional security;
- any requests over and above the minimum requirements;
- future operation and maintenance of any additional assets above the minimum requirements;
- reconfiguration of the Distribution System to meet the transmission customer's requirements where no additional network or fault level capacity is made; and
- for generators only, Reinforcement costs in excess of the high-cost project threshold of £200/kW.

Cost Apportionment Factors

4.26 An extract from Schedule 22 covering the CAFs was incorporated into the proposed legal drafting and amended accordingly to cater for these types of works on the distribution network and the definitions appropriate to them.

4.27 There are only two exceptions;

- where the Reinforcement is in excess of the works specified by the impact assessment and is at the transmission customer's request; and
- unless the switchgear adds network capacity and the Security CAF applies, where the replacement of switchgear results in an increase in fault level capacity solely as a result of the fault level rating of the standard switchgear equipment used by the DNO Party being higher than that of the existing switchgear and that increase in fault level capacity is not needed to accommodate the transmission customer's connection.

In both instances they will be treated as Extension Assets and charged in full as stated in paragraph 4.25 above.

4.28 The two areas where cost apportionment is to be considered, follows the existing CCCM and covers both security and fault level reinforcement. The proposal is to use the same formulas for each with the definitions, but amended to cater for the transmission impact on the distribution assets.

4.29 The legal text attached to the consultation showing the proposed definitions was provided as a clean version since the schedule is new, but to aid the review by Parties the definitions shown below, were shown in strikethrough as compared to those that are currently in Schedule 22.

Existing Capacity	<p>means the Maximum Capacity at the Systems Connection Point. For existing Customers their Existing Capacity will be either:</p> <p>(a) the Maximum Capacity used in the calculation of their use of system charges; or</p> <p>(a) for Customers who are not charged for use of system on the basis of their Maximum Capacity the lower of:</p> <p>No. of phases x nominal phase-neutral voltage (kV) x fuse rating (A); and</p> <p>The rating of the service equipment.</p>
Fault Level Contribution from Connection	<p>is the assessment of the Fault Level contribution from the equipment to be connected taking account of its impact at the appropriate point on the Distribution System. Where an existing Customer requests a change to a connection then the “Fault Level Contribution from Connection” is defined as the incremental increase in Fault Level at the appropriate point on the Distribution System taken from the impact assessment caused by the Customer.</p>
Maximum Capacity	<p>means in relation to any connection the maximum amount of electricity, as agreed with the DNO Party and expressed in kW or kVA, that can be imported from or exported onto our Distribution System</p>
New Fault Level Capacity	<p>is the Fault Level rating, following Reinforcement, of the equipment installed after taking account of any restrictions imposed by the local network Fault Level capacity. For the avoidance of doubt this rule will be used for all equipment types and voltages.</p>
New Network Capacity	<p>is either the secure or non-secure capacity of the Relevant Section of Network (RSN) following Reinforcement. Whether secure or non-secure capacity is applicable depends upon the type of capacity that can be provided from the RSN. For example, if the capacity provided to the Customer by the RSN is secure, but the capacity requested by the Customer at the point of connection is non-secure, the secure capacity will be used. See Example 12.</p>

	<p>The capacity to be used will be based on our assessment of the thermal ratings, voltage change and upstream restrictions and compliance with our relevant design, planning and security of supply policies. The equipment ratings to be used are the appropriate operational rating at the time of the most onerous operational conditions taking account of seasonal ratings and demand.</p>
<p>Relevant Section of Network (RSN)</p>	<p>is that part or parts of the Distribution System which require(s) Reinforcement as stated in the impact assessment. Normally this will comprise:</p> <ul style="list-style-type: none"> — the existing assets, at the voltage level that is being reinforced, that would have been used to supply you (so far as they have not been replaced) had sufficient capacity been available to connect you without Reinforcement; and/or — the new assets, at the same voltage level, that are to be provided by way of Reinforcement. <p>Where it is unclear what assets would have supplied the Customer in the event that sufficient capacity had been available, the existing individual assets with the closest rating to the new assets will be used. See Example 13.</p> <p>There may be more than one RSN (e.g. at different voltage levels).</p>
<p>Required Capacity</p>	<p>is the Maximum Capacity agreed with the Customer. In the case of multiple connections (e.g. a housing development) it may be adjusted after consideration of the effects of diversity. Where the Systems Connection Point requires an existing Customer requests an increase in capacity then it is the increase above the if Existing Capacity.</p>

- 4.30 For the Security CAF the existing capacity is considered to be that at the Systems Connection Point i.e. the boundary between the distribution system and the transmission system, and the new network capacity is the relevant part of the network that required re-enforcement as identified in the impact assessment.
- 4.31 For the Fault Level CAF it is the incremental increase in Fault Level at the appropriate point on the Distribution System taken from the impact assessment, and no change to the current definition of the new fault level capacity.

Recovery of costs for previous works

- 4.32 The new schedule introduces a process whereby any applicants for future transmission connection or modifications that benefit from an earlier reinforcement of the distribution assets relating to a transmission impact assessment on the network may have to pay a contribution to the initial contributor.
- 4.33 The suggestion in paragraph 3.7 above, that distribution modifications should also be considered i.e. benefit from the principles of the ECCR, was rejected by the Working Group on two counts: those being that it is:

- **Outside the scope of this change proposal, and**
- **In contradiction of the ECCR which caters for new connections only.**

- 4.34 The proposed new schedule uses the Electricity (Connection Charges) Regulations 2017 as the basis of the process and amends accordingly its content to make it suitable for the purpose of DCP 392. It however retains the same time periods and de minimis values to be consistent with the application across distribution customers.

- 4.35 It covers:

- Who is eligible to receive a rebate;
- Notification to future transmission customers for the potential to be charged a reimbursement payment and what that charge may be;
- De minimis values;
- Provision of information; and
- The period for which such a rebate may apply.

Other matters which are outside the scope of the CCCM

- 4.36 In the introductory text to the Schedule, consideration was given to paragraph 3 within Schedule 22 which states: “The DNO Party will include within the document containing its Connection Charging Methodology other matters which are outside the scope of the CCCM.”.
- 4.37 There was a view that the charging methodology for works triggered by transmission connected customers that have an impact on the distribution system should be classed as meeting the criteria of Schedule 22, paragraph 3 and as such there should be an obligation to place the methodology of this schedule within the DNO’s own Connection Charging Methodology. The counter view was for the DNO to place this methodology as a separate document on their respective websites.

IDNOs

- 4.38 For the purposes of the consultation, the proposed new Schedule was drafted specific to DNO’s like that of the CCCM. It was noted that the IDNO’s have their own charging methodologies which are subject to approval by Ofgem. In practice many IDNO connection charging methodologies mirror large parts of the CCCM.

- 4.39 Because of this, paragraph 3 of the CCCM covered under paragraph 4.28 would not apply to IDNOs and neither would this schedule.

5 Summary of Consultation and Responses

Summary of responses to the DCP 392 Consultation

- 5.1 The DCP 392 consultation was issued on 21 March 2022 and there was a total of nine responses received.
- 5.2 Set out below are the questions that the Working Group sought views on, and a summary of the responses received, and the Working Group's conclusions are also set out below. The full set of responses and the Working Group's comments are provided in Attachment 5.

Question 1 - Do you understand the intent of DCP 392?

- 5.3 All respondents understood the intent. One requested further clarification on a number of points, some of which were outside the scope of this Change Proposal, the feedback from the Working Group on the points raised by the respondent is detailed within the collated consultation responses document.

Question 2 – Are you aware of any legal, regulatory or licence obligation which would allow, or disallow DNOs to fund works on the distribution system that are triggered by a transmission connecting customer through the DUoS charges?

- 5.4 A number of responders felt that this change falls outside of the current legal, regulatory or licence arrangements. There was a view that it could form part of the DNOs' price control business plans for RIIO-ED2, and where this wasn't included, it would require a price control re-opener should this CP be accepted. It was also noted that such a request may not be granted by Ofgem.
- 5.5 Other responders commented on Transmission Connectees not being a party to DCUSA, The Working Group acknowledged this as an area for further consideration but noted that if CMP 328 was approved, the relationship would be between the DNO and NGESO via the bilateral agreement and the legal text within the schedule would need to be updated accordingly.
- 5.6 One responder touched on the recent Ofgem review regarding the treatment of Transmission costs associated with distribution connections where they indicated in their minded to position, as part of the Access SCR, that these would continue to be charged in full to the connecting customer. This proposal seems to be at odds with that principle.
- 5.7 One responder indicated that they agreed the issue this change is seeking to address does merit exploring, though their preferred approach was for Ofgem to be heavily involved in leading the policy options given the material consequences for current and future customers, similar in materiality to those in current charging SCR's. The Working Group's view is that Ofgem can determine their approach during their decision-making process on this CP be it ED2 re-openers, licence change or the TNUoS taskforce.
- 5.8 Should this change be accepted, one responder suggested that further consideration is required between the ongoing costs for the medium and longer term to cover on-going maintenance; noting that capitalised

O&M could be utilised, otherwise, there would be no recovery of those costs. The Working Group agreed to review this.

Question 3 - Do you agree that the instances outlined in paragraph 4.25 (of the consultation) should be excluded from the proposed CAF? If not, please provide your rationale.

- 5.9 The responders agreed with the instances identified with one area relating to speculative developments being identified for further consideration by the Working Group

Question 4 – Do you agree with the proposal to introduce cost apportionment for Distribution works triggered by Transmission connections? Please provide your rationale.

- 5.10 A number of responders stated they were not supportive of the introduction of CAF for such arrangements quoting a preference of a separate Ofgem led approach, it would introduce a different approach for Distribution connections impacting the transmission network.
- 5.11 One area was identified for further consideration by the Working Group which related to speculative developments

Question 5 - Do you agree with the proposed definitions? If not, please provide alternatives and your rationale for your suggestion/s.

- 5.12 There was a majority support for the definitions however concerns were raised over the same term having two different meanings between this new schedule and the one covering the CCCM. In addition, the term 'Systems Connection Point' is defined in the proposed schedule but is also defined in DCUSA. It may be clearer to include the DCUSA definition. The Working Group agreed to review the legal text definitions.

Question 6 – Do you agree with the application of the principle of the ECCRs to transmission connections triggering distribution works? Please provide your rationale for your response.

- 5.13 There was overall support in principle, however some responders would prefer a change to legislation to support the obligation. This could be possible under the BEIS ECCR review. The key areas of concern are the demand for payment for an earlier connection and the potential of non-payment being received, based on there being no legal obligation to do so because transmission customers are not a party to DCUSA. A Party suggested that there may be a need to add contractual terms and/or a further CUSC change.
- 5.14 Two areas were identified for consideration from the Working Group, relating to the issue of transmission customers not being party to the DCUSA and to the de-minimis values in the ECCR.

Question 7 - Does DCUSA provide the legal basis for DNOs to require subsequent transmission customers to pay for costs associated with previous works? Please provide your rationale for your response.

- 5.15 The majority of responses did not agree that the DCUSA provides the legal basis for DNOs to require subsequent transmission customers to pay for costs associated with previous works as transmission customers are not a party to DCUSA.
- 5.16 One responder suggested that a clause is added into the CUSC, and another suggested a bilateral agreement. A further responder raised concerns over legal challenge should it form part of the impact

assessment just for second comer payments i.e. no actual re-enforcement works required but a cost to pay for an earlier connection that this connection is benefitting from.

Question 8 – Will this process treat transmission customers and distribution customers on the same basis? Please provide your rationale for your response.

5.17 Mixed responses were received, with two responders agreeing that the process would treat transmission customers and distribution customers on the same basis. The remaining responders disagreed, with concerns being raised that costs would not be spread fairly. Most of these comments related to looking at the system as a whole, rather than just distribution or transmission. However, such a consideration is outside the scope of this CP.

Question 9 - Should this Schedule be classed as 'other matters which are outside of the scope of the CCCM' and be included within the DNO's Connection Charging Methodology, or should there be a separate standalone document that can be referred to on the DNO website? Please provide your rationale in support of your preferred approach.

5.18 The Working Group noted that responses were mixed, with three responders stating they feel that this Schedule should be classed as 'other matters which are outside of the scope of the CCCM' and be included within the DNO's Connection Charging Methodology, and three responders stating that it should be a separate standalone document that can be referred to on the DNO website.

5.19 Three responders also stated that they believe neither is appropriate, due to reasons including not supporting the proposal overall and concerns that neither option will have the powers to oblige non-DCUSA parties to comply. The Working Group will consider this further as part of the legal review.

Question 10 – Do you believe that IDNOs should be included within the new schedule? If not, please provide your rationale.

5.20 The Working Group noted that all responders, excluding responses from IDNOs and one who has no specific comments on the matter, were supportive of IDNOs being within the scope of the proposed new Schedule.

5.21 The Working Group agreed that this is a point for consideration.

Question 11 - If this Schedule applied to IDNO's should an obligation be placed upon them regarding the visibility of this charging schedule? If so, suggested wording would be appreciated.

5.22 The majority of responders supported an obligation being placed upon IDNOs regarding the visibility of this charging schedule.

5.23 One responder questioned how an obligation can be placed upon IDNOs when this refers to sections that are not subject to formal industry governance.

5.24 A further three responders either chose not to comment or felt that it would be more appropriate for IDNOs to comment on this question at this stage.

Question 12 – Do you have any comments on the proposed legal text?

5.25 Four responders provided comments on the legal text. One party highlighted the previous raised concern that DCUSA may not be an appropriate legal vehicle for addressing the two issues covered by the proposal. Another raised concern that if this change is approved, it could create an inconsistent approach with Ofgem's SCR decision.

Question 13 - Do you believe that the DCUSA General objectives are better facilitated by this CP? Please provide your rationale.

5.26 A summary of the responses can be found in the table below. The view of the Working Group is contained within section 7.

Respondent	Objective 1	Objective 2	Objective 3	Objective 4	Objective 5	Overall Stance
1.						Does not better facilitate the objectives
2.						Does not better facilitate the objectives
3.	-	Positive	-	-	-	Does better facilitate the objectives
4.	-	-	-	-	-	No response provided
5.	Negative	Negative	Negative	Negative		Does not better facilitate the objectives
6.	Positive	Positive	Positive	Positive	-	Does better facilitate the objectives
7.	Negative	Neutral	-	Negative	-	Does not better facilitate the objectives
8.						Does not better facilitate the objectives
9.						Does not better facilitate the objectives

Question 14 – Are you aware of any wider industry developments that may impact upon or be impacted by this CP?

5.27 The responders identified a range of activities that may impact this CP, most of which have been picked up in the other questions

- CMP328,
- ECCR Statutory Review,
- Access & Forward-Looking Charges SCR,
- Future System Operator (FSO)/Energy Strategy,
- Transaction cost analysis (TCA) Charges, and
- Queue management.

Question 15 - Do you have any other comments on this CP?

5.28 The responses to this question related to the CUSC change, lack of DCUSA governance relating to SCR changes and whole system considerations. On the former this is subject to Authority decision, the second due process was followed, and the latter is outside the scope of DCUSA.

Question 16 – Do you agree with the implementation date? If not, please provide an alternative date and your rationale to support it.

5.29 Three responders noted that they support the implementation date of the Change. The remaining six responders either indicated that they don't support the implementation date, or that they do not wish to comment as they do not support the proposal overall.

5.30 The full set of responses and the Working Group's comments are provided in Attachment 5

6 Working Group Conclusions & Final Solution

6.1 After consideration of the consultation responses, the Working Group identified the following areas for further consideration:

- Powers and Obligations (Potential need for bilateral agreements and/or a subsequent CUSC change);
- Discussion for O&M considerations
- Decisions on
 - whether the schedule is considered as 'other matters' of the CCCM;
 - whether the schedule applies to IDNOs; and
 - IDNO visibility of charging methodology.
- Other areas raised:
 - De minimis values;
 - Speculative connections;
 - High-cost project threshold
 - Definitions; and
 - Security CAF formula.

Powers and Obligations

- 6.2 The Working Group considered the matter of transmission customers not being party to the DCUSA and the potential need for bilateral agreements and/or a subsequent CUSC change.
- 6.3 The Working Group agreed to refer this matter to the DCUSA advisers for consideration during their legal review. The advice provided was that a CUSC modification may be helpful to provide 'a hook' but that this Schedule should be able to stand alone. The legal text was amended to provide additional context and references a bi-lateral agreement relating to the distribution works between both Parties.
- 6.4 After a review with the legal advisors, the Working Group undertook a final RFI on the treatment of the costs.

RFI 3

- 6.5 As stated under paragraph 4.22 the Working Group and the industry have struggled to determine whether costs can be recovered under the existing regulatory framework. The legal advice suggested a more focussed question that DNOs should consider, which was as follows: the below.

"Would this expenditure be treated as part of the Load Related Expenditure and Reconciliation Process? If not, how is it recovered, or is there a need for Ofgem to consider the treatment of such expenditure?"

RFI responses

- 6.6 Three responses were received, all in agreement that there is no current treatment of such expenditure. The full set of responses and the Working Group's comments are provided in Attachment 6.
- 6.7 One responder highlighted that there is no market segment available within the RIGS for which they can associated expenditure towards transmission connected customers.
- 6.8 Another responder outlined that if approved, the change will result in a new schedule and therefore they feel that Ofgem should consider the treatment of the expenditure.
- 6.9 A third responder noted that they do not think this fits into any of the current LRE categories. The response noted that they felt the closest is "general reinforcement" but that it is not really "general" because it is the specific result of a connection to the transmission system. The response highlighted that Ofgem is currently proposing a different definition for LRE in ED2 which is under review and a decision on whether it fits is subject to the final definition.

Working Group conclusions

- 6.10 If the Change Proposal is approved, the Working Group recommend that Ofgem consider whether they are comfortable with the approach taken and also how this is to be treated and either point to an existing arrangement such as LRE or introduce a change to the Licence special conditions to ensure the treatment of such expenditure is captured appropriately.

Discussion for O&M considerations

- 6.11 The Working Group reviewed the query raised over distributors picking up future operational costs on such connections. The Working Group considered the existing arrangements whereby the costs are paid

in full and whether the distributor is legitimately applying a capitalised O&M to the capital connection costs which would cover the ongoing opex as there is nothing which would prohibit/prevent this. No evidence could be found that this practice is being followed and evidence provided that no separate line item on such requests covered such ongoing costs.

- 6.12 The conclusions of the Working Group are that these costs may well exist without this change, so the status quo still remains whether this change is approved or not. No change to the legal text is required to accommodate them.

Decision on whether the Schedule is considered as ‘other matters’ of the CCCM

- 6.13 The Working Group discussed and agreed that the Schedule should not form part of the CCCM under ‘other matters’ as described in Paragraph 1.3 and that it should be a stand-alone document placed on each party’s website to aid visibility.

Decision on whether the Schedule should apply to IDNOs

- 6.14 The Working Group considered whether the Schedule should apply to IDNOs. One Working Group member stated that the CCCM is currently not an obligation on IDNOs and that the regulatory arrangements which govern IDNO connection charging and use of system charging are significantly different from the DNO. Another Working Group member suggested that for consistency, IDNOs should be treated the same as DNOs.
- 6.15 The Working Group discussed and agreed with a majority of five to one, that IDNOs should be included within the Schedule. This decision also helped in supporting the decision under paragraph 4.73 because the CCCM does not apply to IDNOs.

IDNO visibility of charging methodology

- 6.16 The Working Group considered whether an obligation should be placed on IDNOs regarding the visibility of the Schedule. One Working Group member stated that currently there is an obligation within the licence to make this information public and available and that it would make sense for there to be a separate document for IDNOs.
- 6.17 The Working Group unanimously agreed that an obligation should be placed on IDNOs regarding the visibility of the Schedule and that they should have the same requirement placed on DNOs to place it on their website.

De minimis values

- 6.18 The Working Group discussed whether the remaining value, after the deduction of administrative expenses (currently £300), should be different to that of the ECCR and agreed that the value should be the same. The Working Group then considered the impending change to the ECCR and that it would make sense to future proof this value by referencing ‘the value in the ECCR’ rather than including the actual figure. This was agreed however it was acknowledged that the ECCR is due to change late 2022.

Speculative connections

- 6.19 The Working Group agreed that this type of connection request should be treated the same as distribution reconnection requests and was added to the areas where the full costs would be applied.
- 6.20 It should be noted that the term speculative developments is currently under review by DCP407 as part of the Access & Forward Looking Charges (A&FLC) review Significant Code Review (SCR).

High-cost project threshold

- 6.21 The Ofgem decision document on the A&FLC SCR is also introducing, for Demand Connections, a 'high-cost cap' of £1720/kVA. This has been included in this change proposal (now known as high-cost project threshold - see paragraph 4.6 within the legal text) and is also expected in the DCUSA change proposals raised to cater for the SCR decision and as such avoids a housekeeping change at a later date.

Definitions

- 6.22 Concern was raised in the consultation response over the use of the same definition terms but with different meanings within different schedules. The Working Group agreed that a different term was required. Where this is appropriate this is preceded by TRDR, where TRDR stands for Transmission related distribution reinforcement. The amendments to the definitions originally proposed can be seen in Attachment 7.

Security CAF formula

- 6.23 One respondent to the consultation had concerns over the Security CAF formula believing that this favours the transmission customer to that of distribution customers i.e. if it was a distribution new connection the Required Capacity is their Maximum Capacity but because the transmission customer is connecting to the Transmission Network the value used is the additional capacity over that of the Transmission Connection Point so it would only consider the increase in capacity and not their actual capacity.
- 6.24 The Working Group noted the concern but agreed with their original position that these are to two points on the network that are changed as a consequence of the request and that the Distributor may not know what the connection capacity is so can only ever go on the incremental capacity change. It was further understood that this problem may go away under the SCR as the proportion of costs funded is not (subject to the High-cost project threshold etc.) dependent on either the total new capacity or incremental capacity.

7 Legal Text

Legal Text

- 7.1 The legal text for DCP 392 has been reviewed by the DCUSA legal advisors and is provided as Attachment 1.
- 7.2 The DCP 392 legal text introduces a new schedule. It covers nine sections
- Section 1 provides an introduction section indicating that this schedule applies to both DNO and IDNOs relating to the methodology to be applied to new or modified connections to the transmission network that have an impact on the distribution assets;

- Section 2 covers the minimum scheme reflecting the lowest overall capital cost (as estimated by the DNO/IDNO Party) and the conditions and standards associated with its design;
- Section 3 covers the costs to be charged by the DNO/IDNO Party to the Transmission User split into three categories, costs to be recovered in full, costs to be recovered in part and costs to be paid by the Transmission User in respect of works paid for by a previous Transmission User. Each of these have their own sections 3 through to 5 shown below;
- Section 4 covers the costs to be paid in full by the Transmission User and provides the various instances where this would be the case similar to those in the CCCM;
- Section 5 covers the costs charged based on the costs of reinforcement to the distribution network based on an apportionment using one of two cost apportionment factors, dependent upon which factor is driving the requirement for reinforcement:
- Section 6 covers the recovery of costs associated with previous works based on the principles of the ECCR
- Section 7 covers the rebate process based on the principles of the ECCR,
- Section 8 covers the records that need to be retained; and
- Section 9 contains the definitions for this Schedule.

7.3 The Working Group has considered the legal text and is satisfied that it meets the intent of the solution.

8 Relevant Objectives

Assessment Against the DCUSA Objectives

- 8.1 For a DCUSA Change Proposal to be approved it must be demonstrated that it better facilitates the DCUSA Objectives. There are five General Objectives and six Charging Objectives. The full list of objectives is documented in the CP form provided as Attachment 8.
- 8.2 The Working Group considers that the following DCUSA General Objectives are better facilitated by DCP 392. The Working Group notes their rationale for assessing this change against the General Objectives is that although this schedule introduces a charging methodology for transmission connections, the charging objectives stated in the Distribution Licence are specific to the CCCM, EDCM and CDCM which are not impacted by this change.

DCUSA General Objectives	Identified impact
1. The development, maintenance and operation by the DNO Parties and IDNO Parties of efficient, co-ordinated, and economical Distribution Networks	Negative

2. The facilitation of effective competition in the generation and supply of electricity and (so far as is consistent therewith) the promotion of such competition in the sale, distribution and purchase of electricity	Negative
3. The efficient discharge by the DNO Parties and IDNO Parties of obligations imposed upon them in their Distribution Licences	Neutral
4. The promotion of efficiency in the implementation and administration of the DCUSA	Negative
5. Compliance with the Regulation on Cross-Border Exchange in Electricity and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators.	None

- 8.3 The Working Groups views range from positive through to neutral and onwards to negative, but the majority view is that Objective One is not better facilitated. Those that believed it had a positive response cited the correct approach on investments, the counter argument being that the investment may not be able to be recovered through DUoS.
- 8.4 The Working Groups views range from positive through to negative, but the majority view is that Objective Two is not better facilitated. For those that believed it was positive, it enhanced competition by providing a level playing field for those Transmission customers that impacted the Distribution Network. Those that believed it was negative cited that this change, taken in isolation of wider reforms in the cost for connecting to the distribution or transmission system and the ongoing charges for those connections (TNUoS, DUoS etc.) may have a negative impact on the generation and supply of electricity. It was also noted that this change has the potential to exacerbate other distortions which make it preferable to connect generation to the transmission network rather than levelling the playing field between transmission and distribution connected generators.
- 8.5 The Working Groups view on Objective Three is neutral. It must be noted that the Working Group suggested that if this CP was supported it would benefit from a licence change.
- 8.6 The Working Groups views range from neutral through to negative, but the majority view is that Objective Four is not better facilitated. The negative stance stemmed from obligations placed outside of DCUSA are not enforceable. Another view was that duplicating connection charging rules is likely to negatively impact the administration of DCUSA.
- 8.7 The Working Group view is that there is no impact on Objective Five.
- 8.8 The majority view of the Working Group taking into consideration Objectives One to Five is that this CP will have a negative impact on the DCUSA General Objectives.

9 Code Specific Matters

Reference Documents

9.1 Links to reference documents are included in footnotes throughout.

10 Impacts & Other Considerations

Who (i.e., which Industry roles) are impacted?

- 10.1 Transmission customers impacting a DNO Party system will benefit from proportionate charges for works.
- 10.2 DUoS Customers will be picking up the additional costs as stated in paragraph 4.7 above. These costs may be recovered over time from subsequent transmission users as further connections/modifications benefit from previous works as stated in paragraph 4.32 to 4.35

Which processes/systems are impacted?

- 10.3 The DNO/IDNO will have to introduce new processes for determining cost apportionment and the equivalent ECCR refunding that this new schedule introduces.

Impacts on Significant Code Reviews (SCRs) or other significant industry change projects

CMP328

- 10.4 This change proposal is closely linked with CMP328; Connections Triggering Distribution Impact Assessment. It is however not conditional on CMP328 being approved. CMP328 proposes to put in place an appropriate administration process to be utilised when any connection or modification triggers a Distribution impact assessment, however the CUSC proposal does not and cannot cover the DNO's CCCM methodology such as cost apportionment of the works. hence the raising of this change proposal.

Access and Forward-Looking Charges SCR

- 10.5 The minded-to decision on the first part of Ofgem's review of access and forward-looking charges was produced in June 2021. A past modification, DCP384⁸ raised prior to the consultation was held back due to uncertainty over whether it would overlap in scope with the proposals due to come forward under that review, and hence could have been considered in scope of a live SCR under DCUSA 10.23.2. The minded-to decision on the first part of Ofgem's review of access and forward-looking charges has three parts: it proposes that:
 - 1. Connection charges for new DG should be shallower than at present, in that they will no longer be charged the reinforcement costs on the DNO network that result from their connection, one voltage level up (the "voltage rule") (there are related proposals for new embedded demand connections, too)
 - 2. DG of 1 MW to 100 MW should begin to pay GTNUoS charges (there are proposals also in relation to <1 MW DG and removing the current cap on the embedded export tariff)

⁸ [Charging of Third Party DNO Works to Transmission Connected Users](#)

3. Flexible access for new DNO connectee's (already a feature of many new DG connections) on an opt-in basis is proposed to be formalised with some new limitations on the extent of possible curtailment.

None of (1) to (3) above, interacts with this change proposal and Ofgem raised no concerns at the Panel stage when considering whether it impacted the SCR.

10.6 In January 2022 Ofgem published⁹ an update to their minded to position which closed on 21st February 2022. It is noted that the second part has been removed from their minded to position and that this change proposal is likely to be out for consultation before it closes. Ofgem published its decision and direction documents¹⁰ on the 3rd of May 2022.

10.7 It is noted that Ofgem believe that the ECCR needs to be amended to give effect to the proposed SCR charging reforms. They consider that these changes are unlikely to face further reform as a consequence of our coming DUoS review due to the ECCR's explicit connection charging focus, and therefore delay to legislative change should not be necessary. The changes to the ECCRs are a BEIS responsibility and are not part of the SCR and they have conducted a statutory Post Implementation Review and produced a document on their findings (see paragraph 3.8 and 3.9).

Does this Change Proposal impact Other Codes?

- | | |
|-----------|-------------------------------------|
| BSC | <input type="checkbox"/> |
| CUSC | <input checked="" type="checkbox"/> |
| Grid Code | <input type="checkbox"/> |
| MRA | <input type="checkbox"/> |
| SEC | <input type="checkbox"/> |
| Other | <input type="checkbox"/> |
| None | <input type="checkbox"/> |

Consideration of Wider Industry Impacts?

10.8 The Working Group did not identify any additional wider industry impacts other than those already highlighted in other areas.

11 Implementation Date

11.1 The proposed implementation date for DCP 392 is 01 April 2023. The rationale for this is to tie in with the Access SCR implementation date and to allow for process changes to accommodate this CP.

⁹ [Access and Forward-looking Charges Significant Code Review: Consultation on Updates to Minded to Positions and Response to June 2021 Consultation Feedback](#)

¹⁰ [Access and Forward-Looking Charges Significant Code Review: Decision and Direction | Ofgem](#)

12 Voting

12.1 The 392 Change Report was issued to DCUSA Parties for Voting on 23 September 2022.

Part 1 Matter: Authority Decision is Required

Change Solution – Reject

12.2 For the majority of the Party Categories that were eligible to vote, the sum of the Weighted Votes of the Groups in each Party Category which voted to reject the change solution was more than 50%. In accordance with Clause 13.5, the Parties have been deemed to recommend to the Authority that the change solution be rejected.

Implementation Date – Reject

12.3 For the majority of the Party Categories that were eligible to vote, the sum of the Weighted Votes of the Groups in each Party Category which voted to reject the implementation date was more than 50%. In accordance with Clause 13.5, the Parties have been deemed to recommend to the Authority that the implementation date be rejected.

The table below sets out the outcome of the votes that were received in respect of the DCP 392 Change Report that was issued on 23 September 2022 for a period of 15 working days.

DCP 392	WEIGHTED VOTING				
	DNO	IDNO	SUPPLIER	CVA REGISTRANT	GAS SUPPLIER
CHANGE SOLUTION	Reject	Reject	Not Eligible	Not Eligible	Not Eligible
IMPLEMENTATION DATE	Reject	Reject	Not Eligible	Not Eligible	Not Eligible

13 Recommendations

DCUSA Parties Recommendation

13.1 DCUSA Parties have voted on DCP 392 and in accordance with Clause 13.5, the Parties have been deemed to recommend to the Authority that the Change Proposal be rejected.

14 Attachments

- Attachment 1 - DCP 392 Legal Text
- Attachment 2 – Consolidated Votes
- Attachment 3 - RFI 01 Responses
- Attachment 4 - RFI 02 Responses
- Attachment 5 - Consultation Responses & WG Comments

- Attachment 6 - RF1 03 Responses
- Attachment 7 - DCP 392 Defined Terms
- Attachment 8 - DCP 392 Change Proposal