

DCP 461 Working Group - Meeting 01

24 September 2025 at 13:00 - Web-Conference

Attendee	Company
Working Group Members	
Aishwarya Harsure [AH]	NESO
Amanda McFarlane [AMF]	Aurora
Ben Godfrey [BG]	National Grid
Brian Hoy [BH]	ENWL
Claire Witty [CW]	SPEN
Drew Johnstone [DJ]	NPg
Ed Grimsey [EG]	BU-UK
Edda Dirks [ED]	SSE Gen
Hector Perez [HP]	Scottish Power
Helen Stack [HS]	Centrica
Jack Purchase [JP]	National Grid
Joe Colebrook [JC]	Innova
John Harmer [JH]	Waters Wye
Kyle Murchie [KM]	Roadnight Taylor
Liam Sweeney [LS]	Ofgem
Mark Askew [MA]	SSE
Matthew Paige-Stimson [MPS]	National Grid
Monique Periera [MP]	Indigo
Code Administrator	
Craig Booth [CB] (Chair)	ElectraLink
Mel Kendal [MK] (Technical Secretariat)	ElectraLink

Apologies	
Kara Burke [KB]	NPg
Ryan Ward [RW]	Scottish Power

1. Administration

- 1.1 The Working Group reviewed the “Competition Law Guidance” and “Terms of Reference”. All Working Group members agreed to be bound by the Competition Law Guidance for the duration of the meeting and agreed to the Terms of Reference.
- 1.2 An action log has been created and all updates are provided in **Appendix A**.

2. Purpose of the Meeting

- 2.1 The Chair explained that the purpose of this meeting is to review and discuss the Change Proposal within the Working Group and agree next steps.

3. Overview of DCP 461 Change Proposal

- 3.1 The Chair invited the proposer [BG] to provide an overview of the DCP 461 Change Proposal to the Working Group.
- 3.2 BG informed the group that the purpose of this change is to address a growing set of structural, economic, and policy misalignments that are actively hindering the UK’s energy transition.
- 3.3 The variation in regulatory treatment across transmission and distribution customers is creating confusion for customers. A working group should be set up to consider options to improve the customer experience being cognisant of timescales to implement, standardisation across regions and voltage levels, impact of current/future price controls and impact on developer investment confidence. Existing work has developed a number of options and these should be considered by the working group as a priority:
 - Fully socialise via DUoS (with or without High-Cost Cap).
 - Fully socialise via TNUoS.
 - MW minimum threshold and Standard Rate above.
 - Customer apportioned costs with unallocated capacity socialised by DUoS.
 - Stronger and more consistent guidance for Customers.
- 3.4 Due to the potential impact on both distribution and transmission codes, parallel code modifications might be needed.

4. Review and Discussion of the Change Proposal

- 4.1 The Chair invited the Working Group to both review and discuss the DCP 461 Change Proposal.
- 4.2 The key updates can be found below:
- 4.3 Firstly, BG asked the group whether there were any previous examples of where changes were progressed/developed in parallel with other CUSC Changes – ED stated that from a process point of view, it may be worth looking at lessons learned from both the Access SCR and TCR changes. It was also suggested to take a look at learnings from both DCP 434/435 and DCP 424 as these were progressed in parallel with CUSC changes.
- 4.4 The group agreed that taking a look at the learnings from the above changes may be beneficial to enable this change to be progressed smoothly. The Secretariat agreed to take an action to review the above suggested changes and feedback any lessons learned to the group.

ACTION 01/01: The Secretariat to take a look at lessons learned from the Access SCR/TCR changes, and DCP 434/435/424 changes and feedback to the group.

- 4.5 JC did mention that it important to make wider industry aware of changes such as through RFIs and Consultations as it is key that their engagement is received. The Chair confirmed that awareness can be provided to wider industry via RFIs, Consultations and mid-Consultation Q&As; if it is felt that there is a lack of engagement from industry, the Secretariat will naturally reach out to Parties so seek thoughts/comments.
- 4.6 National Grid Presentation - BG
- 4.7 In relation to the issue itself, BG stated that DNOs are not explicitly funded for all connections led transmission reinforcement – it has always been assumed that some of this would be fully funded by Customer Contributions.
- 4.8 Strategic or general reinforcement triggered by the DNO is recovered by NESO/TOs (Transmission Operators) by increasing GSP annual exit charges.
- 4.9 Large generation and demand connections which are identified as triggering transmission reinforcement therefore must fully fund all reinforcement works. It is unattractive due to:
- The first mover carries all the risk. No element of socialisation by the DNO means the costs are jointly and severally apportioned to all applicable connections.
 - With the likely queue attrition – it leaves the first mover potentially left standing picking up all of the costs.
 - It is compounded by all the customer contributions being needed to be provided upfront, rather than recovered through annual exit charges.
- 4.10 BG noted that they do have a number of specific examples where this is blocking connection of low carbon technologies.

4.11 BG provided the group with a number of questions to answer within the development of the solution to this change:

- *What should be the direction on deep or shallow charges for transmission asset costs caused by distribution customers? [addresses infrastructure vs connection asset changes]*
- *How soon do we want a new solution in place – Gate 2 (Nov), 01 April 2026 (ED3 BP), RII04?*
- *Should this be recovered through transmission or distribution? [how to address the above]*
- *What should the scope/depth of recovery be? [application across all customers]*
- *How timely should the recovery be? [second comer/future customer options]*

4.12 MPS queried whether that this change is seeking out the problems with distribution funding to either support/not support connection charges, and whether this can be socialised through DUoS recovery – BG confirmed that this is exactly right, and although the aim is to be cognisant of the CUSC change, the focus needs to be primarily on the solution that will be implemented via the DCUSA change process.

4.13 ED suggested that a better understanding is needed to see how big of a problem this is (i.e., how many Customers are affected?). ED also queried whether this issue has been affected by the Connections Reform and how is this treated? BG explained that an operation was carried out last year to better understand the scale of this problem; the findings shown was around £5.9 billion across a multiple number of price controls. The timescale for this would be around 15-20 years. BG stated that this is a material figure of reinforcement costs that will be affected by this decision.

4.14 In terms of how other DNOs deal with this issue, BG stated that there is a mix of those that have been socialised and fully funded by DUoS customers, and other schemes that are outside of this business plan investment and will need to be fully funded by customers. DNOs are broadly aligned with how this is treated, however there is some variation out there. A number of DNOs have suggested that a more standardised approach would be more desirable.

4.15 JC informed the group that they have reached out to NGED (as apart of the CUSC change) to seek data that they can provide in relation to the number of SGTs (Supergrid Transformers) and infrastructure sites that are being planned. Following this, it was suggested that it may be beneficial to seek this data from other TOs. The Working Group agreed to take an action to provide JC with relevant TO contacts if available and JC will then reach out to them to seek the above data.

ACTION 01/02: Working Group members to provide JC with relevant TO contacts if available.

ACTION 01/03: JC to reach out to TOs to seek available data around the number of SGTs and infrastructure sites that are being planned, and feedback to the Working Group once available.

4.16 ED informed the group of another policy development that may be linked to this change, which is the recent REMA (Review of Electricity Market Arrangements) announcement relating to SSEP (Strategic Spatial Energy Plan) framework and initiatives. There maybe projects are works that may lead to a justification for reinforcement costs being socialised (or not). ED suggested that these potential links may need to be considered.

- 4.17 In terms of size and scale, BG informed the group that roughly 60% of their GSPs are connection assets, whereby all asset costs are funded by distribution customers. The cost of treatment of those assets has been overlooked by Transmission Charging Review (TCR) and Significant Code Review (SCR).
- 4.18 BG explained that they are funded to develop/maintain these assets through New Transmission Capacity Charges (NTCC) total expenditure (totex) allowance and Transmission Connection Point Charges (TCPC) pass through, which can be funded through existing Load Related Expenditure (LRE) allowances or an existing Uncertainty Mechanism.
- 4.19 As of June 2024, BG stated that they have £440m of NTCC CAPEX which means they have agreed to progress with the Energy System Operator (ESO), which have been passed through to customers.
- 4.20 In terms of solution strategy, BG informed the group that the current treatment does not explicitly agree socialisation of these costs for generation, so any generation connection triggering these works could be potentially liable for all costs. BG stated that this is a barrier to decarbonisation.
- 4.21 NGED recommends levelisation of the charging boundary, capacity-based charging and implementation of DSO flexibility markets; to do this, it requires the DNO to be allowed to socialise unapportioned costs (via exit charges over 40+ years) – albeit with the expectation that they will aim to fully recover all costs. As more customers accept contracts for apportioned capacity, Transmission construction agreements will be revised with NESO to remove any residual unapportioned costs.
- 4.22 BG suggested that strategic investment to all GSPs should not be agreed to, but trigger them based on criteria – i.e., where it can credibly demonstrate the need from demand will follow soon as evidenced from our Distribution Future Energy Scenarios (DFES) and stakeholder engagement processes.
- 4.23 ED queried whether there is a scenario whereby additional reinforcements at transmission level that DUoS payers are paying for, which is subsequently being used by transmission connected users? BG agreed that this is correct. Where there is a connection site, there is the ability to guarantee that the local capacity will be available to distribution customers only; however, if another user wanted to connect to that site, there is no recovery through this mechanism currently.
- 4.24 ED suggested that it is key to seek further clarity on if socialisation is proposed, who would have future access to the reinforcement that has been paid for.
- 4.25 MPS suggested that the initial connectee is charged fairly for their proportion of works whilst they are the sole user, but this ceases once it becomes an infrastructure asset.
- 4.26 CW queried what happens if there is a customer who is paying over a period time for their capacity as an SGT but then changes to infrastructure asset – BG stated that up until energisation, the operator can change the amount asked for up front along with the amount to pay for exit charges. With the example presented above, BG explained that if this happens prior to energisation, the costs would be refunded back to the Customer. This would not be able to happen post-energisation.
- 4.27 CW also queried whether the proposed solution would be applied retrospectively to those who have a Gate 2 offer if Ofgem approve it? BG explained that ideally the decision would be made by

November so that the solution can be embedded within the Gate 2 contracts. The Chair clarified that there is currently a 6-month timeline for this change to reach Change Declaration and would therefore be unlikely to have a decision by November 2025, with April 2026 also being quite a tight deadline. The Chair also noted that Ofgem will need time to come to a decision.

- 4.28 Following the above discussion, JC confirmed that the CUSC change will also face timeline challenges and is unlikely to reach a decision prior to when Gate 2 offers are issued. JC also suggested it may be difficult to apply this solution retrospectively to those who have connection agreements and who are energised; however, it should be possible for NESO to allow DNOs to vary their agreement for those Customers who have not yet been energised.
- 4.29 BG presented a table which showed the varied approaches that DNOs are taking; some differences are due to the regional variation of Distributed Energy Resources (DER) uptake and some differences due to transmission voltage levels in Scotland.
- 4.30 It was noted that NGED has the highest volume of DERs seeking connection across all DNOs and double the amount of connection asset GSPs than any other DNO.
- 4.31 Following the table presented comparing DNO approaches, ED suggested that it would be beneficial to highlight what the underlying reasons are for the differences in treatment are and also queried whether a common approach is achievable. JC suggested that standardisation is possible, however, the question is what the impact of this is and what is the acceptable costs of doing this. This needs to be considered when developing the solution.
- 4.32 CUSC Presentation – JC
- 4.33 JC informed the group that distribution customers who trigger new SGTs currently face a ‘postcode lottery’ as to how much they must pay, depending on the classification of GSP that they are connected into. Due to this, DNOs are taking various approaches with how to charge customers.
- 4.34 The group were presented with three possible solutions:
- Option 1 – socialise all embedded triggered Transmission reinforcement through TNUoS.
 - Option 2 – Socialise all embedded triggered Transmission reinforcement through DUoS.
 - Option 3 – Pass embedded triggered Transmission reinforcement charges on to triggering distribution customers but apply a CAF to fix the proportion paid by each customer.
- 4.35 JC suggested that the discussions held in both DCUSA and CUSC Working Groups may influence each other.
- 4.36 The group were informed that the aim is to seek the CUSC Panel approval to make the CUSC change a high priority, with the aim to have a decision required by September 2026 for an April 2027 implementation date. It was noted that if these changes are to be aligned, the CUSC proposal will need to be considered by the Authority together with the DCUSA DCP 461 CP.
- 4.37 JC stated that with any of the suggested options to choose from, new definitions may need to be created in terms of different assets on the transmission network.

- 4.38 MA queried whether all three options can be run through the T3 price control as it currently sits – JC suggested it may be difficult to make changes to this; however, it should be considered for further discussion as the impact on TOs becomes clearer.
- 4.39 JC confirmed that the scope of the CUSC change is not to change the way that TOs are currently charged.
- 4.40 BH queried how these two changes (DCP 461/CMP 460) are going to work together - the Chair confirmed that this point will be taken to the Cross Code Steering Group for further guidance around the appropriate approach.

ACTION 01/04: The Secretariat to take the discussion around timelines for both DCP 461/CMP 460 to the Cross Code Steering Group for further advice on the correct approach.

- 4.41 LS informed the group that there was a recently published document which highlights that deeper connections may be a longer-term solution that may be developed.
- 4.42 Following discussions around timelines, the Chair presented the current work plan to the Working Group for further discussion. The Chair noted that once the Change Declaration is sent to Ofgem for a decision, the timescales would then be out of DCUSAs control in terms of implementation.
- 4.43 BH raised a concern in that if a solution is not presented to Ofgem soon, it may be complicated for Ofgem to make a decision due to ED3 ramifications – it was agreed that the sooner Ofgem receive the Change Declaration, the better. Following this, LS agreed to take an action to seek further guidance internally around when Ofgem would like to see the Change Declaration and update the group at the next meeting.

ACTION 01/05: LS to seek further guidance internally around when Ofgem would like to see the Change Declaration and update the group at the next meeting.

- 4.44 The Working Group discussed and agreed the need for an impact assessment to see what it would look like if costs were to be socialised, and the impact this would have on consumers. One member suggested that they do not believe there is a need for TOs to join the Working Group itself, however, they should be encouraged to respond to any RFIs and Consultations that are issued.
- 4.45 ED mentioned that Ofgem have recently sent back a number of both DCUSA and CUSC changes due to a lack of analysis and showed concern that this could happen again for these changes if a thorough impact assessment is not carried out. MA suggested that this is a practical piece of work that will act as an interim solution. ED also suggested that the connections reform will have a material effect on this issue and therefore resulting in another way of analysing the impact.
- 4.46 BH stated that he was keen to progress this change proposal quickly, noting that the CUSC change was more complicated and would take considerably longer to develop a solution.
- 4.47 BG, as the Proposer, stated that he was comfortable with this approach. MA and MPS also agreed that this would be quicker and cleaner to deliver a solution through the DCUSA to deliver benefits sooner.

4.48 JH stated that the Working Group needs to consider, for any solutions it develops, whether it is giving the appropriate signals on the right places for a Customer to connect to the network.

4.49 It was agreed to schedule the next Working Group meeting as soon as possible to progress this CP.

5. Agenda Items for Next Meeting

5.1 The Working Group discussed the next steps, and the following items were captured:

- Discuss & agree solution(s) to take forward.
- Discuss & agree RFI/impact assessment requirements.

6. Any Other Business

6.1 The Chair asked the group whether there were any other items of business to discuss.

6.2 There were no other items raised.

7. Date of Next Meeting – 30 September 2025

7.1 The next Working Group meeting will be held on 30 September 2025 at 1pm.

8. Attachments

- Attachment 1_DCP 461 Work Plan

APPENDIX A

New and Open Actions

Action Ref.	Action	Owner	Update
01/01	The Secretariat to take a look at lessons learned from the Access SCR/TCR changes, and DCP 434/435 changes and feedback to the group.	Secretariat	New Action.
01/02	Working Group members to provide JC with relevant TO contacts if available.	Working Group	New Action.
01/03	JC to reach out to TOs to seek available data around the number of SGTs and infrastructure sites that are being planned, and feedback to the Working Group once available.	JC	New Action.
01/04	The Secretariat to take the discussion around timelines for both DCP 461/CMP 460 to the Cross Code Steering Group for further advice on the correct approach.	Secretariat	New Action.
01/05	LS to seek further guidance internally around when Ofgem would like to see the Change Declaration and update the group at the next meeting.	LS	New Action.

Closed Actions

Action Ref.			Update