

DCP 461 Working Group Meeting 02

30 September 2025 at 13:00 - Web-Conference

Attendee	Company
Working Group Members	
Aishwarya Harsure [AH]	NESO
Ben Godfrey [BG] (Proposer)	National Grid
Brian Hoy [BH]	ENWL
Catherine Cleary [CC]	Roadnight Taylor
Claire Witty [CW]	SPEN
Damian Clough [DC]	SSE
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
John Harmer [JH]	Waters Wye
Liam Sweeney [LS]	Ofgem
Mark Askew [MA]	SSE
Matthew Paige-Stimson [MPS]	National Grid
Monique Periera [MP]	Indigo
Code Administrator	
Craig Booth [CB]	Chair
Hannah Proffitt [HP]	Secretariat

1. Administration

Recording

- 1.1 The Chair noted that the meeting is being recorded. The purpose of this recording is purely to aid the Technical Secretariat in producing an accurate report of the meeting.

Apologies

- 1.2 No apologies were received ahead of the meeting.

Competition Law Guidance and Terms of Reference

- 1.3 The Working Group agreed to be bound by the Competition Law Guidance for the duration of the meeting.

Minutes of the previous meeting and Open Actions

- 1.4 The Chair advised that the minutes of the previous meeting had not been issued yet due to the short period of time between meetings.
- 1.5 The Chair gave updates on the actions, these are included in the appendix.

2. Purpose of the Meeting

- 2.1 The Chair advised that the purpose of the meeting was to discuss and agree the solutions to take forward and to discuss and agree the RFI/Impact Assessment Requirements.
- 2.2 The Chair summarised that at the previous meeting the group had agreed to develop a solution within DCUSA as it will be quicker, noting that this may end up being an interim solution that is replaced with something else in the future.
- 2.3 The Chair noted that the group had agreed for an impact assessment to be completed, however that this is subject to change due to connections reform which is currently unknown. Therefore appropriate caveats will be needed, although this may be difficult to quantify.
- 2.4 The Chair noted that the group discussed the possibility of using some existing analysis that may still be relevant and could remove the need for some of the RFI work.
- 2.5 The Chair advised that BH had provided a document for the group to discuss which outlines solution options. This is included as **Attachment 1**.

3. Discuss & Agree Solution(s) to Take Forward

- 3.1 ED highlighted that the options shortlisted will provide guidance as to what impact assessment is then needed, and therefore this will be a two-way process. BH agreed.
- 3.2 ED added that there is a link to the price controls and several of the solutions would require price control framework. ED noted that this is out of scope of the DCUSA Working Group and therefore they should flag which options would require work beyond the group.
- 3.3 BH noted that the implications on price control will depend on how the change is implemented and the timing of implementation. BH agreed that this will be part of the consideration of the options.

- 3.4 MPS raised that a number of different solutions were discussed during previous work done by the Energy Networks Association (ENA) and that he believed this proposal was to extend the cost apportionment table rather than an open proposal to consider solution options.
- 3.5 The Proposer (BG) noted that they did want to explore all possible avenues. The Proposer agreed that reviewing the two questions set out in BH's document will aid in deciding which options are in scope for DCP 461 and which are out of scope. The Proposer noted that this will help to shortlist the solution options.
- 3.6 BH presented the document. This outlined two related issues to consider: the fact that there is a postcode lottery for connection costs; and that there is unsustainable financial burden on individual customers.
- 3.7 Regarding the first issue, the postcode lottery, BH explained that this arises from the Transmission charging regime where Infrastructure and non-Infrastructure sites are treated differently. With the increase in Infrastructure sites this is expected to be around a 40:60 split so the likelihood of different treatment arising from which GSP a connection is made to is high.
- 3.8 BH noted that the solution options outlined can be combined in different combinations.

Option 1.1 - No T ("transmission") costs passed through to D ("distribution") customers - This would ensure full consistency irrespective of the classification of the GSP from the T charging.

Option 1.2 - No T costs passed through to D customers unless the GSP is to feed one customer - This would treat the new GSP as sole use and therefore extension assets and be fully chargeable to the connection customer at D. This would retain consistency with D charging principles as the assets would be shared if more than one customer but sole if only the single customer. This may avoid any gaming where a customer would avoid GSP costs if they were directly connected at T but option 1.1 was in place.

- 3.9 MPS questioned whether 1.2 is a caveat of 1.1. BH noted that they are different solutions in terms of legal text drafting.

Option 1.3 - Extend the voltage rule to T charges - An alternative is to extend the D "voltage rule" principle to T charges. If this was applied then generation connecting at 132kV would pay for any 132kV costs at the new GSP; they would not pay for any of the transformer or higher voltage work. Generation connecting at 33kV or below would not be exposed to any costs.

- 3.10 MPS questioned whether, if it was a dedicated GSP for a large DNO connected data centre for example, that the same caveat (option 1.2) should apply.

- 3.11 BH clarified that the options can be done in combination, and that the high cost project threshold could be applied to any of the options.

Option 1.4 - Application of a HCPT - In all the examples above, consideration of whether a HCPT principle should apply would need to be considered. For context, for a 5MW/MVA connection, the thresholds are £1m for generation and £8.6m for demand and for 50MW/MVA are £10m and £86m.

- 3.12 MPS noted that high voltage equipment costs a lot more and that analysis will be needed on what is an appropriate level of high-cost threshold. BH noted that when they did this for the access SCR

distribution it was worked out on a pounds per kVA basis and they found that it was not actually high value but high unit when you took the work divided by the capacity that was being connected. BH noted that if they were going to apply a high-cost project threshold there would be options to look at such as whether existing ones could be utilised or whether a bespoke one would need to be calculated.

- 3.13 BH noted that their thinking was to replicate the approach for other distribution projects. BH suggested that a similar principle could be applied for these transmission costs, either utilising the existing thresholds or recalibrating them specifically for the situation.

Implementation - Implementation of any of these options is likely to result only in a reduction in costs for connecting customers (or no change). Therefore, there is the potential for this to be applied to the application of TMO4+ to the existing queue. If this was the desired approach, then the charging methodology would need to be updated before DNOs issued revised connection offers to successful Gate 2 projects.

- 3.14 BH moved on to the second part of the document regarding the issue of the unsustainable financial burden on individual customers. BH explained that this arises where DNOs do pass on the costs of any T changes to the connecting customers. Where there are a number of customers, these costs are typically shared based on the respective capacities. The issue arises if any customers fall away, either voluntarily withdrawing, being terminated or not meeting Gate 2 requirements. In these situations, the totality of the costs falls to the “last man standing”. This provides uncertainty and well as an increase in costs which can happen at any time in the project lifecycle.

- 3.15 BH outlined the following options.

Option 2.1 - Cost apportionment - A form of cost apportionment could be applied such that any connecting customers only pay a proportion of the new GSP. This would have the effect of fixing the cost exposure for an individual connecting customer and remove the dependency of the actions of others. The approach to cost apportionment could mirror the existing ones for distribution, however, their applicability would need consideration, particularly for fault level. It should be noted that this could result in situations where the charge to the connecting customer is relatively small, for example if a 5MW generator triggered a new GSP, then the cost impact on DUoS customer would be very similar to those in scenario 1 above.

Option 2.2 - Cost apportionment with a threshold - A cost apportionment approach may benefit from an explicit lower threshold below which costs aren't passed through to connecting customers. For England and Wales this could be aligned to the thresholds for the requirement for a Transmission Evaluation Assessment but these vary by GSP at either 1MW or 5MW so would need consideration.

Option 2.3 - Application of the voltage rule to T charges - Consideration of the voltage rule would also be appropriate. Currently a connecting customer does not pay for any reinforcement of the distribution system at the voltage level above its point of connection. A generation connection at HV would therefore not pay for any reinforcement at 33kV or 132kV. The logic of charging them for any transmission assets therefore needs consideration.

Option 2.4 - Application of a HCP - In all the examples above, consideration of whether a HCPT principle should apply would need to be considered. This could mitigate the issue identified in 2.1 but does add complexity.

Implementation - Implementation of any of these options is likely to result in increased costs for some connecting customers. Therefore, the potential for this to be applied to the application of TMO4+ to the existing queue is more challenging. If this was the desired approach, then implementation may need to be considered consistent with how Access SCR was done ie it applies to applications received after a specified date. Customers would be able to cancel an existing contract and reapply but would be subject to the requirements of the new TMO4+ requirements.

- 3.16 JP noted that a key problem, particularly for the distribution customers is that NESO effectively does not look through the DNO when considering whether a site is infrastructure or not, which leads to a disparity between transmission connected customers and distribution connected customers. JP asked about the sole use D customer, noting that a sole customer triggering that GSP or a new GSP is spending a huge amount of money. JP questioned how the ECCR regulations sit alongside these proposals as there is precedent for people paying each other back when someone else has paid a lot of upfront costs.
- 3.17 BH noted that he was thinking of the extreme situation where one D customer was going to be utilising most of the class and there was going to be very little left.
- 3.18 Regarding the question surrounding the regulations, BH noted that the ENA guidance that was drafted to support the ECCR includes transmission costs as being subject to it. If a single customer is only 200 MW triggers the 240 MW GSP and a subsequent 40 gets on, then some of those costs could be charged to that customer. BH noted that the group would need to consider if this is the right approach. BH advised that for a connecting customer, it depends whether it is infrastructure, non-infrastructure or whether it is a GSP that was paid for by one customer. BH noted that the alternative is similar to some of the guidance and ECCR is if a customer chooses to pay for the full cost, and that is the rules, then that is the contract entered into and there is no reimbursement to other customers.
- 3.19 JP highlighted that a challenge with reinforcement has been that over and above the high cost cap, any money paid towards that reinforcement is not recoverable under that process.
- 3.20 BH suggested that you could follow the principle that if a customer is happy to pay it, they do so with full knowledge that even if there is 40 MW left and somebody else uses it, they do not get any money back.
- 3.21 Regarding the postcode lottery discussion, CC noted that one concern that was raised to them was that it is not just a post code lottery and that whether a GSP is an infrastructure asset or a connection asset could change over time. This was influencing customer behaviour because they had an expectation that the charging regime would change. CC suggested that the change should address this to ensure customers are treated the same, and noted that some of the solutions for issue one may resolve this.
- 3.22 MPS noted that this will likely be reliant on how CMP 460 progresses. BH agreed that CMP 460 should progress in parallel but that it is more complicated and likely to be slower than the DCUSA change.
- 3.23 BH noted that option 1.1 provides complete consistency and that some of the variations like 1.2 and 1.4 move away from this slightly but balance the risk to DUoS customers. JP agreed that consistency is important and that differences in methodologies creates complexity. JP noted that 1.2 is an

appropriate solution as typically now one customer connecting at D having triggered a new substation would be expected to pay those costs and that does reduce the gaming risk.

- 3.24 Regarding passing entirely through DUoS, MPS noted that the role of the EDCM should be considered in terms of how cost reflectively apportioned the annual transmission connection charges are. BH agreed that this could be considered as the group work through the options.
- 3.25 ED suggested that the solutions are presented in a tabular format and with some numeric examples included to allow comparison and to see what the customer would be expected to pay in each option. ED suggested that these vary by the level of spare capacity over what the customer needs. ED suggested that a column is added stating who picks up the remaining costs and what that would be in the specific numeric example.
- 3.26 JP and MPS agreed to help BH with the figures needed.

Action 02/01 - BH to present the solution options in a table format with three numerical examples for each (varying in level of spare capacity). A column to be added stating who picks up the remaining costs and what that would be. JP and MPS agreed to help BH with the figures needed.

- 3.27 JH raised concerns about adding on to residual and noted that this seems like the wrong direction to go in. JH noted that some of these solutions could end up being unfair to the vast majority of customers who are incrementally going to be paying more socialised costs that could have been avoided or minimised if they were put somewhere else.
- 3.28 ED noted that we may not want to create a situation where connection locations are encouraged which is not efficient for the system. ED noted that at the previous meeting she had highlighted the REMA (Review of Electricity Market Arrangements) framework and suggested that these potential links may need to be considered.
- 3.29 MPS asked to what extent any solutions better align with the current distribution reinforcement charging methodology apportionment. MPS suggested that this could be one consideration when assessing the options.
- 3.30 JH noted that transmission reinforcement costs occur even if you are an infrastructure GSP, it is just they are socialised. JH asked that, in the interest of consistency, could distribution customers be asked to contribute to those and create a negative charge that is socialised as well, just so there is consistency. BH agreed that this is worth considering, however that it is outside the scope of this change and may be more relevant to the CUSC modification.
- 3.31 BH asked how many solutions could be taken forward in a CP. The Chair confirmed that three alternatives can be included in addition to the original solution. The Chair noted that this includes any variations on solutions.
- 3.32 The Chair added that the group would need to consider how the solutions would be presented during voting, whether this would be a case of Parties stating preferences or approving one and rejecting the others. The Chair noted that this can prove to be complicated. The Chair noted that the consultation may help shortlist the options, if industry has clear opinions.

- 3.33 BH suggested that it may be necessary to split the DCP into two. The Chair noted that there is a risk that one DCP is approved whilst the other is not, so these should not be issued as dependant proposals (allowing Ofgem to approve the solution it considers best, if any).
- 3.34 ED asked if there was a limit on how many solutions can be consulted on. The Chair noted that there is not and that all of the options on BH's document could be included in the consultation and that Parties could be asked to consider the pros and cons of each. The Chair noted that this could be a large consultation with lengthy responses to review.
- 3.35 The Chair asked members if there were any solution options that they felt were more appropriate to take forward than others. The Chair also asked if the tabular view/impact assessment (Action 02/01) would be beneficial to parties in responding to the consultation.
- 3.36 MA agreed that shortlisting would be useful in progressing, even if the long list was also included in the consultation, with an explanation of the groups shortlisting justification.
- 3.37 BH agreed that completing the impact assessment on all of the options would be challenging and asked if any solutions could be eliminated. BH suggested that they could consult on the options as a set of principles rather than trying to work out exact numbers at this stage.
- 3.38 The Working Group agreed for the impact assessment to be carried out once a shortlist of options had been obtained following the consultation. This could then help present the impacts for Ofgem's consideration.
- 3.39 The Working Group agreed to go back through the options and to consider which to take forward to the consultation.
- 3.40 MA highlighted that in most cases these solutions should be about removing costs from customers but going down the list of solutions this rule gets less certain. MA noted that the high-cost cap or even the voltage rules could end up with customers getting new costs. MA noted that if the group want to have a solution in place as soon as possible, consistency for reform, that leads to option 1.1. Or 1.2 but that there are still some customers that may get new costs at that point.
- 3.41 MPS highlighted the timing of CMP 460 and noted that transmission connection charging is likely to change in the future, especially if there is a dwindling population of connection sites and increasing proportion of infrastructure sites. MPS noted that there will likely be some form of replacement charging signal to replace connection charging that is more pervasive across sole use or shared transmission sites.
- 3.42 MPS noted the downside of full socialisation through DUoS if a later transmission charging approach resulted in appropriately proportioned basis of local asset charging for all types of site, infrastructure site or connection site.
- 3.43 MPS suggested it would seem inappropriate to continue socialising through DUoS indefinitely (or have to revert back from full socialising) if a consistent transmission charging signal across all Grid Supply Points (shared or not shared) could enable targeted proportional charging to any connecting DNO customers, thereby fairly and cost reflectively reducing the residual of transmission local service asset charging recovered via DUoS.

- 3.44 BH noted that they are only looking at connection charges and not DUoS charges. If it changes, CMP 460 will have to flag the consequential change needed and another modification may need to be raised. BH highlighted that the Working Group need to consider what is currently the case and not worry about the future unknowns.
- 3.45 The Working Group discussed and agreed that 1.1 to 1.4 should all be brought forward to be consulted on.
- 3.46 The Chair asked if the Working Group wanted to also take forward all of the second set of options, or whether there were any that could be ruled out at this stage.
- 3.47 Regarding option 2.3, MPS asked for clarity on whether it is only the 132 KV transmission works that would be subject to apportionment. BH agreed that this is consistent with how it is done for others with the voltage rules applied. Transformers get the higher voltage, so just looking at the 132 KV switchgear. MPS noted that therefore around 75 to 80 percent of the costs would go through DUoS on that basis.
- 3.48 Regarding the voltage rule, MA noted that this is drafted more for Wales and London and questioned what would be done for Scotland. BH suggested that the same logic would be applied but agreed this should be considered and potentially added in.
- 3.49 The Chair noted that the next item on the agenda was to consider the impact assessment but suggested that this is not necessary as the group do not yet know which options they will assess against. The Chair asked whether they could request the data for the impact assessment now or whether they need to wait to find out which options are going to be included.
- 3.50 MA suggested that they could look at the data they already have to see if it could be used to support the consultation. Regarding using existing data, caveats would need to be included stating that this data was from pre connection reform which will likely have an impact.
- 3.51 MA highlighted that some work was completed in this area by the ENA group and agreed to find this to see if any of it can be used by the Working Group. BH raised that the previous ENA work may give a worst-case scenario.

Action 02/02 - MA, BH and BG to pull together work done by previous ENA group to see if it can be used by the Working Group.

- 3.52 The Chair asked if the group were in a position to consider the legal text, noting that drafting legal text for all of the options would be very time consuming and not all solutions will be taken forward. BH suggested that an indicative legal text could be put together which could identify which parts may need to change. The Chair agreed that it would be more of a legal text commentary at this stage.
- 3.53 The Chair agreed to review Schedule 22 and highlight paragraphs that will be targeted by each solution. The Chair noted that the Working Group could validate this at the next meeting.

Action 02/03 – Chair to review Schedule 22 and highlight paragraphs that will be targeted by each solution. WG to validate at the next meeting.

3.54 The Chair also agreed to produce a first draft of a consultation.

Action 02/04 – Chair to produce a first draft of the consultation.

3.55 ED noted that the invitation has been sent out to join the CMP 460 Working Group with responses due by the 17th of October. ED questioned how the two changes will be coordinated. BH noted that there will likely be an overlap in attendees, however that the timescales will not be aligned and the DCUSA consultation could be issued before the CUSC group meet for the first time. BH summarised that there will likely be overlap but the groups should function independently.

3.56 MA suggested that CMP 460 is flagged in the DCP 461 consultation and that the difference is timelines is highlighted. The Chair noted that CMP 460 will also be highlighted on the DCUSA website as a related change to DCP 461.

4. Next Steps & Work Plan

4.1 The Working Group agreed to meet again on Friday 10 October at 10am. The following matters will be discussed:

- Review BH's table of options with scenarios;
- Review ENA data (if available);
- Review Schedule 22 to identify legal text that is in scope of each solution; and
- Draft the consultation.

5. Any Other Business

5.1 No other business was raised

6. Attachments

6.1 Attachment 1 - DCP 461 Options

New & Open Actions

Action Ref.	Action	Owner	Update
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	Action ongoing. <i>Awaiting confirmation from colleagues. LS added that Ofgem can try to work to a tighter timescale if possible. In terms of the ability of Ofgem to make a decision, LS advised that they need as much information as possible and as for it to be as accurate as possible.</i>
02/01	BH to present the solution options in a table format with three numerical examples for each (varying in level of spare capacity). A column to be added stating who picks up the remaining costs and what that would be. JP and MPS agreed to help BH with the figures needed.	BH, JP and MPS	New action.
02/02	MA, BH and BG to pull together work done by previous ENA group to see if it can be used by the Working Group.	MA, BH and BG	New action.
02/03	Chair to review Schedule 22 and highlight paragraphs that will be targeted by each solution. WG to validate at the next meeting.	Chair	New action.

02/04	Chair to produce a first draft of the consultation.	Chair	<i>New action.</i>
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Closed Actions

Action Ref.		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	<i>Action closed.</i> <i>The group agreed this was no longer relevant following the decision to progress DCP 461 quickly, separate from the CUSC change.</i>
01/02	Working Group members to provide JC with relevant TO contacts if available.	Working Group	<i>Action closed.</i> <i>The group agreed this was no longer relevant following the decision to progress DCP 461 quickly, separate from the CUSC change.</i>
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	<i>Action closed.</i> <i>The group agreed this was no longer relevant following the decision to progress DCP 461 quickly, separate from the CUSC change.</i>

DCUSA

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	<i>Action closed.</i> <i>The group agreed this was no longer relevant following the decision to progress DCP 461 quickly, separate from the CUSC change.</i>
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