Public

CUSC Modification Workgroup Consultation

CMP460: Improving Transmission Connection Asset Charging

Overview: This modification proposes improvements to the framework for charging Transmission Connection Assets. The proposal seeks to socialise costs and cap customer contributions to create a more certain and fair charging methodology.

Modification process & timetable

1. **Proposal Form** 08 September 2025
2. **Workgroup Consultation** 28 January 2026 - 18 February 2026
3. **Workgroup Report** 14 May 2026
4. **Code Administrator Consultation** 22 May 2026 - 15 June 2026
5. **Draft Final Modification Report** 23 July 2026
6. **Final Modification Report** 10 August 2026
7. **Implementation** 01 April 2027

Have 5 minutes? Read our Executive summary
Have 60 minutes? Read the full Workgroup Consultation
Have 120 minutes? Read the full Workgroup Consultation and Annexes.

Status summary The Workgroup are seeking your views on the work completed to date to form the final solution to the issue raised.

This modification is expected to have a: High impact
Transmission Owners, Distribution Network Owners, Generators, Demand Customers, Transmission System Operators

Governance route	Standard Governance modification with assessment by a Workgroup	
Who can I talk to about the change?	**Proposer:** Joe Colebrook Joe@innova.co.uk	**Code Administrator Contact:** jessica.rivalland@neso.energy
How do I respond?	Send your response proforma to cusc.team@neso.energy by **5pm** on **18 February 20**	

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Executive Summary

The CMP460 modification aims to improve the charging framework for Transmission Connection Assets by socialising the cost of shareable Transmission Assets through Transmission Network Use of System (TNUoS), thereby promoting a more equitable and predictable charging methodology. It has been raised to address significant financial and procedural challenges faced by Users, particularly distribution Users. The key challenges are cost uncertainty and liabilities linked to new Transmission Asset reinforcement.

What is the issue?

The existing definitions of Transmission Asset and Connection Asset create inconsistencies, where a User is liable for significant connection charges due to the decisions of other Users rather than due to the Transmission Reinforcement works they have triggered. One User can be charged for the full cost of Transmission Assets because they are the sole User. This User is charged even if the Transmission Assets can be utilised by other, as yet undefined, Users in the future. Whereas another User can trigger the same reinforcement elsewhere and pay nothing because they share a Grid Supply Point (GSP) with other existing Users.

This issue leads to unpredictability in charges, increased financial exposure for Distribution Network Operators (DNOs), and delays in strategic grid development. This lack of clarity deters investment, particularly in low-carbon and community energy projects.

What is the solution and when will it come into effect?

Proposer's solution: The Proposer's solution redefines Infrastructure Asset and Connection Asset to socialise, via TNUoS, the costs associated with shareable, now or in the future, Transmission Assets**.**

Implementation date: Implementation date is 01 April 2027

What is the impact if this change is made?

If the modification is implemented, the impact will primarily be an increase in cost predictability and reduced financial risk for embedded distribution customers and DNOs. Overall, this change is expected to promote faster strategic grid development and enhance collaboration among Users, ultimately benefiting the whole energy system.

Interactions

This modification interacts with several other industry initiatives, particularly in the context of network charging reforms. It requires coordination with the National Energy System (NESO) and Transmission Owners (TOs) to revise construction agreements. Additionally, it aligns with the Connections Review and other regulatory reforms aimed at improving the overall framework for network charging.

The solution must also consider coordination with NESO and TOs to revise construction agreements, alignment with the End-to-End Connections Review, and wider regulatory reforms to network charging.

What is the issue?

What is the defect the Proposer believes this modification will address?

The current transmission charging framework creates significant financial and procedural challenges for embedded distribution customers, particularly when Super Grid Transformer (SGT) reinforcement is triggered at GSPs. These reinforcements are often classified as Connection Assets, meaning the full cost is passed directly to the DNO, even when the reinforcement benefits multiple Users or supports strategic grid development. However, DNOs currently lack a clear, regulated framework to pass these costs through to the initiating customer or to share them across future Users. This results in:

- **Cost uncertainty** for embedded Generators and Demand customers, who may face unpredictable and disproportionate charges.
- **Financial exposure** for DNOs, who must absorb multi-million-pound liabilities without a recovery mechanism.
- **Inconsistent treatment** across regions and voltage levels, depending on how assets are classified e.g. as Transmission Connection Assets or Infrastructure Assets.
- **Investment deterrence**, especially for low-carbon and community energy projects that cannot absorb significant liabilities.
- **Misalignment** with distribution charging principles, where second-comer rules and cost apportionment are standard practice.
- **Strategic grid development delays**, as reinforcement decisions are deferred due to unclear funding pathways.

Where distribution customers trigger Transmission Reinforcement at 'Connection Asset' sites, the cost is passed on by NESO to the relevant DNO, and from the DNO to the customer, or group of customers, who trigger the works. The cost of these works identified at a wide number of GSPs currently ranges from £12m to £60m per GSP, usually too much for individual distribution connections to fund. Many DNOs have determined that if a group of customers triggers the Transmission Reinforcement, the cost is split proportionally between those customers, pro rata on their capacity. This means that if customers in the group terminate their offers, the remaining customers pick up a higher proportion of the cost, until theoretically one customer could be left to fund the full cost.

Some DNOs have sought funding through distribution price controls for Transmission Reinforcement. Most Transmission Reinforcement included in the distribution price controls is for gradual growth in Demand, rather than by step changes in Demand caused by individual connections.

At GSPs where there are two or more DNOs, or a DNO and another customer, the site is classified as an 'infrastructure site'. At these sites, the cost of Transmission Reinforcement is socialised and funded through TNUoS charges.

At some GSPs, instead of offering multiple individual SGT tertiary winding connections, TOs have amended offers to provide a single SGT solely for the connecting customers, i.e. a 'Grid Park', for a group of three tertiary winding customers. The Grid Park SGT is classified as an Infrastructure Asset (because it is supplying multiple customers) and so it is funded through TNUoS charges. However, if those customers had applied as three embedded connections, they would have been charged for the SGT reinforcement as a Transmission Connection Asset.

Ofgem has previously identified this as an issue in the June 2021 'Access and Forward-looking Charges Significant Code Review: consultation on minded positions' document, sections 3.27 to 3.34.

Ofgem again identified this issue in the Connections Action Plan (CAP) action 3.5c iv published in November 2023. The action defined in the CAP is;

'ESO and network companies to continue to identify, and take actions to resolve, areas where a lack of consistency or standardisation is leading to poor outcomes for customers and/or the wider electricity system.'

The Energy Networks Association (ENA) Strategic Connections Group (SCG) developed 6 possible solutions (A-F), which were presented to the Connections Delivery Board (CDB) in April 2024. The CAP, the work completed by the SCG, and the steer from the CDB clearly indicate there is an issue that industry needs to resolve. This Proposal aims to complete action 3.5c iv - ensuring consistency including the allocation of costs - from the CAP and conclude the work started by the SCG.

Why change?

In recent years, there has been a considerable increase in requirements for new or upgraded Transmission Assets, leading to an increase of attributable enabling Transmission Reinforcement works across Great Britain (GB). This increase can largely be attributed to the significant increase in connection applications across both the transmission and distribution systems.

The lack of transparency and predictability of Transmission Connection Asset Charging undermines investor confidence, creates regional disparities, and slows progress toward net-zero targets.

The current transmission charging framework for SGT reinforcement at GSPs is structurally misaligned with the principles of fairness, efficiency, and strategic planning that underpin distribution charging. It places the full cost of transmission upgrades on the first distribution-connected customer, often a low-carbon Generator or large-scale Demand User, without any mechanism for cost recovery from future beneficiaries. This creates a high-risk, high-cost environment that actively deters investment and undermines the UK's decarbonisation goals.

Evidence from National Grid Electricity Distribution (NGED's) internal analysis shows that approximately 60% of their GSPs are classified as Connection Assets, meaning all associated transmission costs are passed directly to distribution customers. This classification results in a postcode lottery, where customers connecting to infrastructure sites benefit from socialised costs via TNUoS, while those at connection sites face multi-million-pound liabilities. The inconsistency is compounded by regional variations in Transmission Asset classification and DNO charging practices, leading to unpredictable outcomes and distorted locational signals.

The lack of second-comer rules at the transmission level further exacerbates the problem. Unlike distribution charging, where cost apportionment and recovery mechanisms are well established, transmission-connected customers bear the full cost of reinforcement even when future Users will benefit. This not only penalises early movers but also delays strategic grid development, as DNOs defer reinforcement decisions due to unclear funding pathways.

This modification is not just a technical fix—it's a strategic enabler. It removes barriers to investment, supports coordinated grid planning, and ensures that the costs of enabling infrastructure are shared equitably across beneficiaries. It also complements wider reforms such as the End-to-End Connections Review and the development of Distribution System Operator (DSO) markets.

The Gate 2 to Whole Queue (G2TWQ) process implemented via CMP435: 'Application of Gate 2 Criteria to existing contracted background', is likely to reduce the size of the connection queue and therefore, reduce the number of GSPs that need transmission Connection Assets to be built. Although the relative magnitude of the issue may be reduced the Proposer still expects many GSPs to be impacted and the value of Transmission Connection Asset works to be £100m's after the G2TWQ process has concluded. Projects which are still in the queue and impacted by this issue will likely be 'ready to connect' and therefore the issue may have a greater impact on their commercial decision making.

The Proposer has requested data from National Grid Electricity Transmission (NGET) on the number of GSPs impacted before and after G2TWQ.

In short, reforming the transmission charging boundary is essential to unlock the full potential of the UK's energy transition. It will create a level playing field for all customers, accelerate low-carbon deployment, and ensure that grid development keeps pace with Demand in a fair, efficient, and future-proofed way.

What is the solution?

Proposer's Original solution

The Proposer recommends changing the definition of an Infrastructure Asset to include all Transmission Owned Assets that can be reasonably used by multiple Users, either now or in the future, i.e. the assets are 'shareable' between multiple Users.

The Proposer believes this will develop a fairer, more transparent, and strategically aligned framework for charging transmission Connection Assets—particularly SGT reinforcements triggered by embedded distribution customers. The solution addresses both the immediate cost burden on individual customers and the broader structural misalignment between transmission and distribution charging regimes.

The solution will reclassify some Transmission Connection Assets as Infrastructure Assets. Worked Examples to show how assets are reclassified are detailed in **Annex 03**. There are several key implications of the proposed solution:

- The solution will classify Transmission Assets triggered by distribution Users as Infrastructure Assets, unless there is a clear justification that the Transmission Assets can only be used by one distribution User.
- There will be no change to how grid parks will be classified, unless the User requires all the network capacity created by the grid park. The majority of assets for a grid park will be charged as Infrastructure Assets.
- There will be no change to how tertiary connections are classified, and Users will still need to pay Connection Asset Charges.
- The solution will classify Transmission Assets triggered by Demand Users as Infrastructure Assets, unless there is a clear justification that the Transmission Assets can only be used by one Demand User.

The Proposer believes a distribution User nearly always has a mix of Demand and generation at each GSP, and therefore any Transmission Assets can provide capacity that can be used by the embedded Demand and embedded generation. Therefore, it can be argued that Transmission Assets provide a whole system benefit.

The Proposer understands that the cost of Infrastructure Assets is recovered through TNUoS. The Local Substation Tariff, which is charged to generation Users only, is not directly related to the value of Infrastructure Assets at a GSP, and therefore, the Generation Local Substation Tariff is unlikely to increase to cover the cost of additional Infrastructure Assets. The Proposer's solution will increase the amount of TNUoS recovered through the Transmission Demand Residual (TDR), which is paid by all Demand Users, i.e. consumers. An impact assessment has been completed by the Proposer and is detailed further in the Workgroup considerations section and **Annex 05**. Further explanation on how Infrastructure Asset costs are recovered is in the Workgroup considerations section of this report.

The solution would align the charging incentive between distribution and transmission. If Demand connects at distribution or transmission, it does not have to pay for the Transmission Owned Assets that can be used to connect other customers (embedded or directly connected). If generation connects at distribution or transmission, the project does not have to pay for Transmission Owned Assets that can be used to connect other customers (embedded or directly connected).

As part of the solution, the Proposer has created a workbook of examples, **Annex 03**, which can be used as the basis of a guidance document to provide clarity to Users and ensure they understand how Transmission Assets are classified and charged. The Proposer has provided a comparison of the baseline vs the original proposal in **Annex 04.**

The Proposer does not advocate blanket strategic investment at all GSPs. Instead, reinforcement should be triggered based on credible evidence of future Demand or generation, supported by Distribution Future Energy Scenarios (DFES) forecasts, connection queues, and stakeholder engagement. This ensures that investment is targeted, efficient, and aligned with net-zero objectives. The Proposer believes that existing regulation such as [Revenues = Incentives + Innovation + Outputs (RIIO)] business plans for networks, extended timelines to build new infrastructure, and transmission and System Operator licence conditions, should significantly mitigate the risk of inefficient investment in the Transmission Network. Ultimately, the solution aims to remove barriers to low-carbon connections, reduce regional disparities, and create a level playing field for all customers, at both transmission and distribution, while maintaining the lowest whole system cost to electricity consumers.

Workgroup considerations

The Workgroup convened 6 times to discuss the issue as identified by the Proposer within the scope of the defect, develop potential solutions, and evaluate the Proposal in relation to the Applicable Code Objectives.

Workgroup Discussion ahead of the Workgroup Consultation

Solution Options

The Proposer presented detailed worked examples comparing the baseline and proposed options for asset classification and cost allocation. The Proposer explained the structure of the worked examples, which can be found in **Annex 03**, and clarified that the examples assume an Air Insulated Switchgear (AIS), with variations for Gas Insulated Switchgear (GIS) noted. The Workgroup discussed the implications for DNOs, grid parks, and final Demand Users, including the need for a clear definition of 'shareable' assets and the potential requirement for changes to Section 11 of the code.

The Proposer presented three options:

- **Option 1:** Shareable Transmission Assets classified as Infrastructure Assets: The Proposer outlined Option 1, where shareable assets, now or in the future, are classified as Infrastructure Assets.
- **Option 2:** All Transmission Assets as Connection Assets: Option 2 was presented as a model where all Transmission Assets triggered by Users are treated as Connection Assets and charged to the triggering User.
- **Option 3:** Proportional Cost Sharing: The Proposer described Option 3, were all Transmission Assets triggered by Users are treated as Connection Assets. However, Users are charged on a proportionally based on their use of Transmission Assets.

Option 1

Proposes that any Transmission Asset that can be shared now or in the future is classified as Infrastructure Assets and the cost recovered via TNUoS, while assets for sole use are treated as Connection Assets and charged to the triggering User. The Workgroup noted that clear legal text changes to the Connection and Use of System Code (CUSC) are required to transparently define “shareable” assets and the criteria for sole-use i.e. shareable assets. The Proposer explained that directly connected Demand Users triggering assets that are not shareable would pay for those assets, because it was not possible for Transmission Owners to connect other Users to those assets in the future. Transmission Assets that are triggered by DNO networks are generally considered to shareable and can benefit multiple Users, so their assets are argued to be 'Shareable' by default.

A Workgroup member raised concerns about consistency, arguing that DNOs and directly connected Users should be treated the same if they are the sole beneficiaries of an asset, to ensure cost reflectivity. Another Workgroup member flagged the need for careful legal drafting to define "full capacity" and "shareability," as practical use may not match asset capacity exactly. The Workgroup discussed how to handle cases where a DNO GSP serves only one customer, suggesting that in such cases, costs might be passed through, aligning with similar options in DCP461: Reducing the Impact of Transmission Distribution Charges'.

A Workgroup member highlighted real-world scenarios where a DNO GSP might have only one customer and raised questions about hybrid sites with both import and export, suggesting proportional cost allocation may be needed. Workgroup members warned against creating incentives for Users to game the system by choosing DNO connections to avoid charges, stressing the need for rules that prevent inefficient outcomes.

The Proposer clarified that Option 1 would not change the User Commitment or Final Sums securities methodology, as assets classified as Infrastructure Assets or Connection Assets would follow existing security arrangements.

Option 2

Option 2 treats all local reinforcement triggered by Users as Connection Assets, with the full cost charged to the triggering User (DNO, Demand, or generation), rather than socialised through TNUoS. The Workgroup discussed the need for a refund or rebate mechanism (similar to second comer charges in distribution) so that if a second User later benefits from the assets, the original User can be compensated. A Workgroup member noted that, unlike distribution, where charges are paid upfront, transmission connection charges are typically annualised, making refunds or cost apportionment more complex to administer. This could require changes to the charging approach if Option 2 is adopted.

The Workgroup noted that under Option 2, tertiary Users connecting later would likely need to contribute to the cost of existing assets, potentially through a rebate to the DNO.

The specifics would depend on whether a rebate methodology is implemented. The Proposer and a Workgroup member clarified that "User" in this context could be a DNO, Demand, or Generation User, and that DNOs would decide how to recover these costs from their customers. A Workgroup member noted that if tertiary Users must pay a share of costs, it could reduce the attractiveness of tertiary connections, but the option would still exist for those seeking quicker or more flexible connections.

Option 3

Option 3 is similar to Option 2 but charges Users for Connection Assets based on their proportional use (capacity-based), rather than the full cost to the triggering User. A mechanism to fairly calculate the proportion of the asset utilised by the User would need to be further developed by the Workgroup. The Workbook of Examples for Option 3 in **Annex 03** includes a proposed equation to calculate the proportion. The Workgroup noted that implementing Option 3 would require a robust method for DNOs and Demand Users to declare a "maximum demand capability", akin to Transmission Entry Capacity (TEC) for generation, and discussed the challenges of updating this value over time. A Workgroup member noted that equipment comes in discrete sizes, so proportional charging should reflect the sum of User capacities, not just minimum asset size, to avoid unfairly charging consumers for unused capacity.

The Workgroup discussed how to handle situations where the requirements of a User change e.g. load growth or reduction, questioning whether charges should be reallocated and how to avoid penalising Users who did not trigger upgrades. The Proposer suggested that tertiary Users would contribute proportionally to all shared assets, and that when new Users connect, their payments would effectively reimburse the socialised costs previously covered by TNUoS. Some Workgroup members recognised that proportional charging could require complex administration, including rules for refunds if Users terminate or if new Users connect, and questioned whether new legislation, like a transmission equivalent of the Capacity Calculation Region (CCR) would be needed. One workgroup member believes the CUSC already allows for proportional charging. It is possible the scope of the [Electricity (Connection Charges) Regulations (ECCR)] may need to be amended to include the cost of transmission connection works incurred by the DNO and ensure subsequent DNO customers are charged appropriately, and the triggering DNO customer is refunded as other embedded customers utilise the Transmission Connection Assets. This change would need to be implemented through a Distribution Connections and Use of Systems Code (DCUSA) modification, such as DCP461.

Proposer preferred solution

The Proposer confirmed that Option 1 is their preferred solution, as it aligns charging principles between transmission and distribution, treats all GSPs consistently, and classifies assets as infrastructure if they are shared or could be shared in the future, with only sole-use assets treated as Connection Assets. The Proposer noted that Option 1 is neutral on cost reflectivity, as it is not improving upon the baseline which also has limited cost reflectivity. The Proposer's solution does not improve the cost reflectivity of local substation charges and flagged the difficulty of being fully cost-reflective for DNO-triggered Transmission Assets due to the mix of Demand and generation within the distribution networks. A Workgroup member suggested that Option 1 would reduce cost reflectivity by reclassifying assets from Connection Assets to Infrastructure Assets and therefore removing Connection Asset charges for Users and suggested that unless a substitute (such as a local transmission charge) is introduced, it risks creating a subsidy and a vacuum in cost signals.

Another Workgroup member asked if shifting costs to TNUoS could risk Ofgem refusing funding for expensive schemes, potentially impacting customers who have reached a Financial Investment Decision (FID). They noted the need for a legislative equivalent to ECCR if refunds are involved. A Workgroup member highlighted that customers seek certainty, but Option 1 could undermine cost reflectivity and the principle of beneficiaries paying, leading to consumers subsidising assets that do not benefit them.

Another Workgroup member suggested that Option 1 could incentivise Generators to seek distribution connections to avoid TNUoS, creating a competition/distortion concern unless the TNUoS methodology is reformed. The Proposer responded that Option 1 actually aligns transmission and distribution treatment, and commercial differences remain. A Workgroup member added that market distortions already exist, especially with grid parks, and Option 1 may improve alignment.

The Workgroup discussed the impact of ongoing Ofgem/ Department for Energy Security and Net Zero (DESNZ) transmission charging and connection depth reform [Revised National Pricing (RNP)], noting that the RNP review is ongoing and while Ofgem may pause transmission modifications, work on CMP460 should continue until further guidance is issued. A Workgroup member clarified that Connection Asset ownership remains with the transmission operator, and grid parks or multi-node substations can be efficient solutions to avoid costly distribution upgrades. The Proposer noted that Option 1 may require TOs to reopen their business plans if assets shift from Connection to Infrastructure, but mechanisms may exist to recover costs without reopening. They also noted that Option 1 removes some cost signals for smart solutions, but time signals and Ofgem's investment approval still incentivise efficiency. Option 2, by contrast, may discourage anticipatory investment. The Workgroup discussed the classification of assets in various scenarios, including grid parks, tertiary connections, and final Demand Users, providing technical insights and raising questions about cost apportionment, User definitions, and the treatment of shared assets.

The Proposer's preferred solution of Option 1 recommends recovering the costs of 'shareable' transmission Connection Assets through TNUoS charges. The Proposer believes this approach is the most positive when measured against the CUSC charging objectives, especially objectives (d) and (h), and is neutral regarding objectives (e), (f), and (g).

Key Points:

- Option 1 aligns charging incentives between distribution and transmission. Both Demand and generation projects, whether they connect at distribution or transmission, would not pay for Transmission Owned Assets that can be used to connect other Users.
- This option provides cost certainty to all Users, supporting investment and improving competition in the electricity supply market.
- It is straightforward to implement, making the process of calculating Connection Asset charges easy to understand and administer.
- While Option 1 will reduce cost reflectivity (since local substation charges under TNUoS are not directly related to the value of Connection Assets at a GSP and not charged back to the User triggering the Connection Asset costs), the Proposer believes it is overall the most favourable compared to the Baseline, Option 2, and Option 3.
- The Proposer notes that a follow-on modification, to reform local substation charges, could address any cost reflectivity concerns.

Infrastructure Assets charging and definition

Workgroup members discussed how Infrastructure Assets are charged, especially the local substation charge, and whether it varies by the number of SGTs. The Proposer presented the response from the NESO TNUoS Revenue team. The discussion on Infrastructure Assets and charging clarified the parameters that determine local substation charges for directly connected generation. These charges are influenced by factors such as voltage, redundancy, and total generation volume, and are standardised across the country. Therefore, the Proposer confirmed that the local substation charge is not directly proportional to the number of SGT at the GSP and adding additional Infrastructure Assets at a GSP may not increase the local substation tariff.

The Proposer pointed out that local substation charges for Infrastructure Assets are only applied to directly-connected Generators and are not locational, depending only on redundancy, voltage, and substation rating single vs double circuit; the scale shows in a small table in NESO's annual Statement of Charges. A Workgroup member clarified that asset sizing does (coarsely[1], and only on a binary basis of whether bigger or small than 1320 MW) influence the charge, which the Proposer acknowledged. The Workgroup discussed the complexity and fairness of charging for SGTs and Connection Assets, the need for cost certainty and reflectivity for all parties, the interaction with DCP461, and the challenge of collecting relevant data while balancing accuracy, sensitivity, and timelines.

The Workgroup highlighted the need to evaluate whether current charging models, particularly for substations, are fair and cost-reflective, and whether changes in asset classification (e.g., from connection to infrastructure) impact TNUoS tariffs. Moving assets from connection to infrastructure increases the total costs recovered by TOs via TNUoS, which are then spread across all Users, potentially leading to inequities in cost distribution. The Workgroup noted that due to the €2.50/MWh cap on generation tariffs, all of the cost is likely to be put on Demand Users via the Transmission Demand Residual (TDR) banded tariffs.

The importance of considering how changes to Infrastructure Asset charging would interact with other regulatory frameworks, such as the Strategic Spatial Energy Plan (SSEP), the Regional Energy System Plans (RESP) and DNO charging methodologies was also discussed.

There was a discussion that revolved around the distinction between shared and non-shared assets in energy infrastructure, particularly substations, and how these classifications impact charging mechanisms. Shared assets are those used by multiple customers, while non-shared assets are dedicated to a single User, but the concept of "potentially shareable" assets was introduced by the Proposer to signal the potential for future shared use, influencing cost allocation and predictability.

The Workgroup recognised that changing Asset definitions or introducing new categories could have complex legal and grandfathering implications, this will be under legal review and will involve careful drafting.

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[1] See Table 1.10 Onshore Local Substation Tariffs (£/kW) at https://www.neso.energy/document/362701/download

A Workgroup member explained the mechanics of partial capital contributions and annual charges, with another Workgroup member raising the challenge of allocating costs when both generation and Demand customers connect to the same asset. The Workgroup agreed that this issue needs further discussion and clear rules.

Cost Reflectivity

The Workgroup noted the need to balance cost reflectivity with simplicity and fairness. They highlighted the potential for unintended consequences, such as incentivising inefficient connections or creating discrepancies between transmission and distribution charging.

Applicability

The Proposal would be applied to the Transmission Assets triggered and used by all Users defined in the CUSC i.e. distribution Users, Demand Users, and generation Users.

The Proposer summarised their view of when CMP460 is applicable. They identified three categories for retrospective application of CMP460: (1) already connected Users (no change to charges); (2) contracted but not yet connected Users (contracts would be updated to reflect CMP460 asset classification); and (3) Users requesting changes after implementation (asset classification and charges updated per CMP460). The Proposer stated that CMP460 should not be applicable to already connected Customers, as this could cause issues for investors. However, they stated that accepted but not yet connected offers would need to be updated to reflect the new arrangements from the Implementation Date.

The Proposer highlighted that contracted Users who have taken financial investment decisions may face significant risk if their contracts are updated. The Proposer suggested two possible approaches for charging assets when changes occur: Either only charge new assets under the CMP460 methodology, or charge all assets based on current asset values when a change is made. It was suggested that the latter would be more consistent with existing principles.

A Workgroup member noted that applicability and implementation could be tailored to each solution option, rather than applying a generic rule, as impacts differ depending on whether charges are added or removed. Another Workgroup member noted a query they had raised to NESO in 2024 on their approach to grid parks, where a sole User pays for the remaining asset life minus years already paid. They confirmed that this was not a formal NESO policy. The Proposer responded that CMP460 aims to provide clear policy direction for such cases.

A Workgroup member asked how long DNOs would be protected from new charges and the implications for cost reflectivity if indefinite grandfathering is allowed. Another Workgroup member asked for clarity on definitions, with the Proposer confirming that all embedded projects will be in scope under CMP460. The Proposer also clarified that any changes to TNUoS would take effect from the start of the next financial year, likely April 2027.

A Workgroup member observed that if this Proposal was applied to contracted but not yet connected Users, there may be some unintended consequences and behaviours. If CMP460 comes into force on the 01 of April 2027 (current best estimate if the modification is accepted by Ofgem). It may incentivise those distribution projects with current project progression costs to seek delayed connection dates to avoid exposure to these connection costs. This may have implications for the ability to deliver Clean Power 2030 (CP30). However, it was accepted that the number of projects impacted by this scenario was not known and so the materiality was uncertain.

Workgroup Consultation question 1: Do you agree with the Proposers view on when the new definition of Infrastructure Assets and Connection Assets should be applied to new and existing connection agreements, and therefore amend the connection charges in a User's agreement?

Impact assessment of the Original Proposal

The Proposer received data from National Grid Electricity Transmission (NGET) detailing the number of SGTs planned to be constructed over the next 9 years and the split between Connection Sites and Infrastructure Sites, and the split between Distribution Users and other Users. NESO provided data on the total planned Capital expenditure on Connection Assets over the next nine years, using data from existing connection agreements, this will include data from both distribution Users and other Users.

The data received is based on existing connection agreements i.e. pre-Gate 2 offers, as the Gate 2 to Whole Queue (CMP435) is still being implemented by NESO and the Networks at the time of this report. It is likely that the absolute capital expenditure on Connection Assets will be reduced once the connections queue is reformed and around 500GW of capacity is removed from the connections queue.

The impact assessments suggest that reclassifying all existing Connection Assets as Infrastructure Assets could increase the TDR for Domestic customers by £0.10 a year in 2027-28 and up to £2.30 a year in 2040-41. The complete impact analysis can be found in **Annex 05**.

The impact assessment does not account for inflation.

Some Connection Assets will not be reclassified as Infrastructure Assets as they will not be shareable and can only benefit one User. It is not possible to know the % of existing Connection Assets

One reason for the relatively low impact on the TDR is that the cost of Connection Assets is typically recovered as one lump sum paid by the User when the connection is energised, whereas the cost of Infrastructure Assets is typically recovered over the lifetime of the assets (usually 40 years). The impact assessment assumes a 2% operational cost for maintaining and operating the additional Infrastructure Assets.

It must be noted that many GSPs in the UK are classified as Infrastructure Sites, i.e. they have more than one User Connected. The Baseline already classifies any Transmission Assets at infrastructure sites as Infrastructure assets, which means many assets which one may expect to be included in the impact assessment are not included when comparing the TDR in the Baseline and the Original Proposal.

It must be noted that many GSPs in the UK are classified as Infrastructure Sites, i.e. they have more than one User Connected. The Baseline already classifies any Transmission Assets at infrastructure sites as Infrastructure assets, which means many assets which one may expect to be included in the impact assessment are not included when comparing the TDR in the Baseline and the Original Proposal. Making it clear some infrastructure costs are socialised.

Workgroup Consultation question 2: Is moving the cost to TDR reasonable?

Consideration of Relevant DCUSA Modifications

A Workgroup member asked whether this modification could dictate how DNOs pass on charges to their Customers, suggesting that this is the remit of DCUSA DCP461 rather than this modification. The Proposer agreed, stating this modification can only determine what is charged to DNOs, not how they recover it.

Ofgem were asked for further clarification on non-discriminatory solutions and was asked about the potential impact of the ongoing TNUoS review and broader regulatory reforms on this modification. The Ofgem representative confirmed that policy developments are at an early stage, with too many variables to determine the extent of interaction.

When reviewing the Terms of Reference, the Workgroup members identified additional potentially relevant modifications beyond DCP461, including 'DCP464: DNO Connection Applications: Treatment of Existing Assets' and 'DCP392: Charging of Third Party DNO Works to Transmission Connection Users'. The consensus was that DCP461 should be monitored for consistency of principles rather than treated as directly relevant to

CMP460. The Proposer presented their review regarding DCP392 in that it is clear from the decision letter that there were concerns with applying the ECCR to transmission-connected customers because they are not a party to the CUSC, and the ECCR is enacted through secondary legislation. CMP460 does not have the same issue, as it is looking at how to charge distribution network Users and other parties who are party to the CUSC. This is also why it is believed that a DCUSA and CUSC modification are required in parallel. Ofgem rejected DCP392 because it did not think it was a fair charging regime.

The Workgroup noted the interaction with DCUSA modification DCP461, which deals with how DNOs recover the cost of Transmission Connection Assets, whatever costs are charged to DNOs by NESO under either baseline or CMP460. A Workgroup member highlighted that any approved CUSC and DCUSA solutions should be aligned, which Ofgem is considered likely to pay attention to. A Workgroup member reported back on DCP461 Workgroup discussions with set of solution options ranging from full socialisation of Transmission Connection Asset costs to proportional charging, to a clarified status quo. It was noted that options under DCP461 may act as short-term fixes to problems that CMP460 is also trying to solve. Both modifications should “acknowledge” each other, but they do not need to take identical approaches (indeed they are operating in different charging domains as CMP460 is about what costs are passed across to the DNOs by NESO vs what is retained in TNUoS, and DCP461 is about how DNOs recover the costs that are passed through to them by NESO. They are in a sense complementary, for example the decision taken on one may affect the decision on what is the ideal solution for the other, but at the same time formally they are entirely distinct).

How Tertiary and Grid Parks are Treated under the Baseline

Workgroup members discussed how grid parks and tertiary connections could affect Asset classification, with differing interpretations among the Workgroup. The Workgroup agreed to seek clarification from TOs and to document these scenarios with worked examples showing how assets would be charged under different options.

There were further discussions regarding tertiary connections. For instance, when a single User connects via a tertiary winding of a transformer, the SGT is classified as an Infrastructure Asset due to having two Users, while the 33 kV transformer and switchgear are classified as Connection Assets. There was some debate about whether all SGTs at a site should be classified as Infrastructure Assets when a tertiary connection is involved on one of the SGTs.

In the context of grid parks, a single-User grid park classified the SGT and 33 kV bus bar as Connection Assets, with the 33 kV bay and feeder classified as User assets.

Conversely, in a multiple-User grid park, the SGT and 33 kV bus bar were classified as infrastructure Assets, while the 33 kV bays for each User were classified as Connection Assets. Also discussed were directly connected final Demand Users, such as data centres, where the 400 kV bay, transformers, and 132 kV bay were classified as Connection Assets, indicating that the User assets began at the 132 kV bay.

The Baseline Current Capabilities, Operations, and Limitations

The baseline connection charge arrangements are on the basis of recovery made over the transmission Connection Asset book life, typically in CUSC 40 years. Arrangements within CUSC, specifically clause 14.3.12, exist to give the User discretion to pay back all or some of the Connection Asset capital in lump sums if the User wishes. A worked example spreadsheet is included in **Annex 06** to this consultation.

The User can opt to pay a proportion of its choice as capital contributions, for example the Megawatt (MW) capacity proportional to a DNO's embedded customer's need.

The selection of 100% capital contribution by DNOs under clause 14.3.12 is due to an absence of RIIO-ED regulatory funding for some transmission connection works and not due to an absence of a mechanism in CUSC for payment over time. The use of this pre-existing mechanism requires no change to Transmission Asset classifications

The baseline CUSC states 10% minimum capital repayments. A minor administrative modification to reduce the minimum capital contribution, for example to 2% to relate to 5MW need of a 240MW upgrade could be made. Such a modification would require no change to Transmission Asset classification.

The CUSC clause 14.3.12's % minimum limit of capital contribution towards transmission Connection Assets does not appear to apply to an initial capital contribution, for example at time of construction, such as would already be reflected in the starting connection charges. Potentially no modification of the lower % limit would be required in respect of an initial connection charging position (such as incorporating a 2% contribution from a DNO customer).

Existing CUSC 14.3.12

A User can choose to make a capital contribution based on the allocated and depreciated NAV of a commissioned asset. For a capital contribution to take account at the start of charging year n, the User may, at most once per year, make a full or partial capital contribution of at least 10% of the NAV prevailing as of 31st March in year n-1. The User shall notify the Company of the capital contribution amount no later than 1st September in year n-1, and pay the capital contribution 45 days prior to the start of charging year n which will be applied to the NAV prevailing at the start of year n. As the *capital component of the connection charge for year n will reduce as a result of the capital contribution, a reduced rate of return element will be payable and a lower security requirement will be required in charging year n and subsequent years.*

Draft legal text

The draft legal text is to be developed by the Workgroup. The proposed solution will require amendments to Section 14, mainly Part 1. The solution may require the creation of new definitions for Connection Asset and Infrastructure Assets or other types of assets in Section 11 of the CUSC.

The definition of Transmission Connection Asset and Infrastructure Asset is defined in sections 14.2.5 to 14.2.8.

What is the impact of this change?

Improving the transmission Connection Asset charging framework will impact many parties across the energy sector. While the proposal introduces a shift in cost allocation, it is designed to deliver long-term benefits by removing investment barriers, improving regional equity, and aligning transmission charging with distribution charging.

Embedded Generators

Embedded Generators, particularly low-carbon and community-led projects, stand to benefit significantly. Under current arrangements, they face unpredictable and often prohibitive costs when triggering transmission reinforcement at GSPs. By introducing socialised or apportioned cost mechanisms, the proposal reduces financial risk, improves transparency, and enables more equitable access to the grid. This will accelerate the deployment of renewables and support the UK's net-zero targets.

Embedded Demand Customers

Large-scale Demand customers connected via distribution networks face uncertainty when their load growth triggers transmission upgrades. With no clear framework for cost recovery or apportionment, they may be exposed to full reinforcement costs, despite benefiting from shared infrastructure. The proposed changes will introduce predictability and fairness, allowing demand customers to only pay for what they use, and plan growth with greater confidence. Socialisation may shift some cost recovery to the wider consumer base, and Demand customers may have an increase in network charges.

Non-embedded Demand Users

Large-scale Demand customers connected via transmission networks face uncertainty when their load growth triggers transmission upgrades. With no clear framework for cost recovery or apportionment, they may be exposed to full reinforcement costs, despite benefiting from shared infrastructure. The proposed changes will introduce predictability and fairness, allowing Demand customers to only pay for what they use, and plan growth with greater confidence.

Socialisation may shift some cost recovery to the wider consumer base, and Demand customers may have an increase in network charges.

Distribution Network Owners

DNOs absorb the full cost of Transmission Reinforcement classified as Connection Assets, without a well-defined regulated mechanism to pass these costs through to customers. This creates financial exposure and operational uncertainty, particularly when reinforcement is strategic or benefits multiple Users. The Proposal offers DNOs a clearer framework for cost recovery—whether via Distribution Use of System (DUoS), TNUoS, or a hybrid model—and enables better coordination with TOs and NESO. It also supports the development of flexibility markets and non-physical alternatives.

Transmission Owners

For TOs, the proposal introduces a more strategic and coordinated approach to reinforcement planning. TOs can invest in shared assets with greater certainty and reduced administrative complexity. The Proposal also encourages earlier engagement with DNOs and embedded customers

Consumers

Socialisation may shift some cost recovery to the wider consumer base; it also ensures that reinforcement decisions are made based on system need. The final solution should consider how networks will be incentivised to minimise the whole system cost and ensure appropriate utilisation of new Transmission Reinforcements.

Original Proposer's assessment against Code Objectives

Original Proposer's assessment against CUSC Code Objectives	
Relevant Objective	**Identified impact**
(d) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;	**Positive** The proposal would align the charging incentive between distribution and transmission. If Demand or generation chooses to connect to the transmission

	network or the distribution network, and the assets can be shared by Users, it does not have to pay up front for the Transmission Owned Assets it has triggered. The proposal reduces financial risk, improves transparency, allowing more customers to connect to the electricity network, and connection costs will be more equitable. This will increase competition.
(e) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C11 requirements of a connect and manage connection);	**Neutral** The proposal could reduce the cost reflectivity as the local substation charges element of TNUoS are not directly related to the value of the Connection Assets at a GSP. A follow-on modification could correct this. However, is it fundamentally difficult to separate the cost associated with Demand and the cost associated with generation, as Connection Assets can create capacity for both embedded generation and embedded Demand. This is especially true for distribution networks or private networks where the demand and generation offset each other and reduce the need for Transmission Assets.
(f) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable,	**Neutral**

properly takes account of the developments in transmission licensees' transmission businesses and the ISOP business*;	This proposal provides a long-term solution for TOs to pass on costs that are triggered by connecting customers. The proposal helps reduce the risk of inefficient investment by TOs. The proposal could remove the cost signals that incentivise smart solutions instead of network reinforcement e.g. Active Network Management. However, the time signal i.e. longer connection dates, should still be an incentive to implement smart solutions. NESO and Ofgem can also incentivise networks to implement smart solutions using connection agreements and business plan determinations.
(g) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency **; and	**Neutral** The proposal does not have an impact or dependency on the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency.
(h) Promoting efficiency in the implementation and administration of the system charging methodology.	**Positive** The proposal provides clarity on the framework for Transmission Reinforcement cost recovery and ensures all customers are treated equitably. Reduced ambiguity should reduce administrative complexity and improve the efficiency of the CUSC.

	The proposal is straightforward to implement. The process to calculate Connection Asset charges will be easy to understand and implement.

** See Electricity System Operator Licence*

***The Electricity Regulation referred to in objective (d) is Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast) as it has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006.*

Proposer's assessment of the impact of the modification on the stakeholder / consumer benefit categories	
Stakeholder / consumer benefit categories	**Identified impact**
Improved safety and reliability of the system	**Neutral** There will be no change to the safety and reliability of the transmission system due to this Proposal.
Lower bills than would otherwise be the case	**Positive** This modification will improve competition in the electricity supply by providing a consistent and equitable framework for embedded customers and customers connecting directly to the transmission network. The modification should also improve strategic network planning at the transmission and distribution interface, leading to optimised network investment and lower bills for consumers.
Benefits for society as a whole	**Neutral** This modification focuses on how costs are apportioned, and therefore, the impact on society as a whole will not change.
Reduced environmental damage	**Positive** This proposal will reduce barriers to entry for low-carbon connections. The increased number of low-

	carbon Generators will reduce greenhouse gas emissions and reduce the impact of climate change.
Improved quality of service	**Positive** The proposal provides clarity on the framework for Transmission Reinforcement cost recovery and ensures all customers are treated fairly. Reduced ambiguity and financial certainty should support all customers, particularly community energy and small and medium-sized businesses.

When will this change take place?

Implementation date

01 April 2027

Date decision required by

30 September 2026 (note that 'CMP292; Introducing a Section 8 cut-off date for changes to the Charging Methodologies[2]' is relevant as all charging methodologies including connections charges, are within its scope). Please note that this proposal could need to be considered by the Authority together with the DCUSA modification DCP461, as the preferred approach to GSP Transmission Asset cost allocation in various cases is likely to affect the decisions on both change proposals.

Gate 2 offers are expected to be issued from October 2025 onwards with all Gate 2 offers being issued by the end of Q1 2026. A decision date of 30 September 2026 is likely to mean there is a period of uncertainty for customers that have accepted Gate 2 offers. The uncertainty on Transmission Connection Assets Charging is likely to delay FID, which will delay procurement, and therefore delay energisation of embedded projects. The delay caused by the prolonged uncertainty will put the delivery of Clean Power 2030 targets at risk. It is important that this proposed modification is progressed as quickly as

[2] CUSC mod CMP292, in force, requires relevant CUSC mods to be passed by 30 September ahead of their implementation year, and relates to any change to "any of the charging methodologies as defined in the CUSC", and so includes in its scope BSUoS mods as well as TNUoS mods, and the connection charging methodology (CUSC 8.2). CMP292 provides exceptions to the deadline for urgent modifications, modifications raised by or at the direction of the Authority, and where the Authority has directed otherwise (even if the mod was neither raised as urgent, nor raised by or at the direction of Ofgem. Footnote 1 of the decision document notes re : such exceptions, "…any such decision would be taken on the merits of individual proposals at the time")

possible to minimise the time between Gate 2 offers being accepted and a decision being made.

Implementation approach

Implementation may require updates to Bilateral Connection Agreements (BCA) between NESO and customers, particularly DNOs.

Interactions

☒CUSC	☐BSC	☐STC	☐SQSS
☐European Network Codes	☐ EBR Article 18 T&Cs[1]	☒Other modifications	☒Other

The proposal interacts with DCUSA modification DCP461.

The proposal will interact with Ofgem's proposed reform of network charging signals. Ofgem's 21 July 2025 open letter specifically includes Ofgem considering making transmission charging "deeper", including via connection charges. This Proposal may require approval and/or implementation to be aligned to the intended timing/outcomes of Ofgem's review to avoid volatility and uncertainty.

The Proposal may interact, peripherally with RIIO-ED3 funding arrangements in respect of Connection Assets required by DNOs.

How to respond

Standard Workgroup Consultation questions

1. Do you believe that the Original Proposal better facilitates the Applicable Objectives versus the current baseline?
2. Do you support the proposed implementation approach?
3. Do you have any other comments?
4. Do you wish to raise a Workgroup Consultation Alternative request for the Workgroup to consider?
5. Do you agree with the Workgroup's assessment that the modification does not impact the European Electricity Balancing Regulation (EBR) Article 18 terms and conditions held within the Code?

Specific Workgroup Consultation questions

6. Do you agree with the Proposer's view on when the new definition of Infrastructure Assets and Connection Assets should be applied to new and existing connection agreements, and therefore amend the connection charges in a User's agreement?
7. Is moving the cost to TDR reasonable?

The Workgroup is seeking the views of CUSC Users and other interested parties in relation to the issues noted in this document and specifically in response to the questions above.

Please send your response to cusc.team@neso.energy using the response pro-forma which can be found on the CMP460 modification page.

In accordance with Governance Rules if you wish to raise a Workgroup Consultation Alternative Request please fill in the form which you can find at the above link.

If you wish to submit a confidential response, mark the relevant box on your consultation proforma. Confidential responses will be disclosed to the Authority in full but, unless agreed otherwise, will not be shared with the Panel, Workgroup or the industry and may therefore not influence the debate to the same extent as a non-confidential response.

Acronyms, key terms and reference material

Acronym / key term	Meaning
AIS	Air Insulated Switchgear
BSC	Balancing and Settlement Code
CAF	Capacity Allocation Factor
CAP	Connections Action Plan
CCR	Capacity Calculation Region
CDB	Connections Delivery Board
CP30	Clean Power 2030
CUSC	Connection and Use of System Code
DCMDG	Distribution Charging Methodologies Development Group

DCUSA	Distribution Connections and Use of Systems Code
DESNZ	Department for Energy Security and Net Zero
DFES	Distribution Future Energy Scenarios
DNO	Distribution Network Operator
DSO	Distribution System Operator
DUoS	Distribution Use of System
EBR	Electricity Balancing Regulation
ECCR	Electricity (Connection Charges) Regulations
ENA	Energy Networks Association
FID	Financial Investment Decisions
G2TWQ	Gate 2 to Whole Queue
GC	Grid Code
GIS	Gas Insulated Switchgear
LRE	Load-Related Expenditure
RESP	Regional Energy System Plans
RNP	Revised National Pricing
SSEP	Strategic Spatial Energy Plan
SQSS	Security and Quality of Supply Standards
STC	System Operator Transmission Owner Code
T&Cs	Terms and Conditions
GSP	Grid Supply Point
NGED	National Grid Electricity Distribution
NGET	National Grid Electricity Transmission

NESO	National Energy System Operator
NTCC	New Transmission Capacity Charges
RIIO	Revenues = Incentives + Innovation + Outputs
SCG	Strategic Connections Group
SGT	Super Grid Transformer
TCMF	Transmission Charging Methodology Forum
TDR	Transmission Demand Residual
TEC	Transmission Entry Capacity
TO	Transmission Owner
TNUoS	Transmission Network Use of System

Reference material

- DCP461 - https://www.dcusa.co.uk/group/dcp-461-working-group/
- Roadnight Taylor Podcast on Super Grid Transformer Charging - https://roadnighttaylor.co.uk/connectology/podcasts/podcast-super-grid-transformer-charging-full-2/
- Connections Action Plan published November 2023 - https://assets.publishing.service.gov.uk/media/6581730523b70a000d234bb0/connections-action-plan-desnz-ofgem.pdf
- Ofgem Access and Forward-looking Charges Significant Code Review: consultation on minded positions June 2021 https://www.ofgem.gov.uk/consultation/access-and-forward-looking-charges-significant-code-review-consultation-minded-positions
- Connections Delivery Board April 2024 Minutes - https://www.energynetworks.org/assets/images/Publications/2024/240520-april-connections-delivery-board-meeting-minutes.pdf?1757327112

- Roadnight Taylor Open Letter on Reforming Super Grid Transformer Charging September 2023 - https://roadnighttaylor.co.uk/wp-content/uploads/2023/09/Open-letter-to-Ofgem-regarding-distortion-in-charging-for-supergrid-transformer-reinforcement.pdf

Annexes

Annex	Information
Annex 01	CMP460 Proposal Form
Annex 02	CMP460 Terms of Reference V2
Annex 03	CMP460 Worked Examples Baseline vs the Original Proposal
Annex 04	CMP460 Comparison of Worked Examples Baseline vs the Original Proposal
Annex 05	CMP460 Original Proposal Charging Impact Assessment - NESO Data
Annex 06	CMP460 Partial Capital Contribution Model