Public

CMP460: Improving Transmission Connection Asset Charging

Workgroup 1, 13 November 2025

Online Meeting via Teams

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WELCOME

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Agenda

Topics to be discussed	Lead
Introductions	Chair
Code Modification Process Overview • Workgroup Responsibilities and Membership • Workgroup Alternatives and Workgroup Vote	Chair
Timeline	Chair
Proposer's Presentation	Proposer
Questions from Workgroup Members	All
Terms of Reference	All
Cross Code Impacts	All
Any Other Business	Chair
Next Steps	Chair

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Code Modification Process Overview

Jess Rivalland – NESO Code Administrator

Code Modification Process Overview

Talk to us → Raise a mod → Refine solution → Consult → Decision → Implement

Forums

Panels

Workgroups
(Workgroup Consultations)

Ofgem/Panel

Refine Solution

Workgroups

- If the proposed solution requires further input from industry in order to develop the solution, a Workgroup will be set up.
- The Workgroup will:
  - Further refine the solution, in their discussions and by holding a **Workgroup Consultation**.
  - Consider other solutions, and may raise **Alternative Modifications** to be considered alongside the Original Modification.
  - Have a **Workgroup Vote** so views of the Workgroup members can be expressed in the Workgroup Report which is presented to Panel.

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Consult

Code Administrator Consultation

- The Code Administrator runs a consultation on the **final solution(s)**, to gather final views from industry before a decision is made on the modification.

- After this, the modification report is voted on by Panel who also give their views on the solution.

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Decision

- Dependent on the Governance Route that was decided by Panel when the modification was raised.
- **Standard Governance:** Ofgem makes the decision on whether or not the modification is implemented .
- **Self-Governance:** Panel makes the decision on whether or not the modification is implemented.
    - An appeals window is opened for 15 days following the Final Self Governance Modification Report being published

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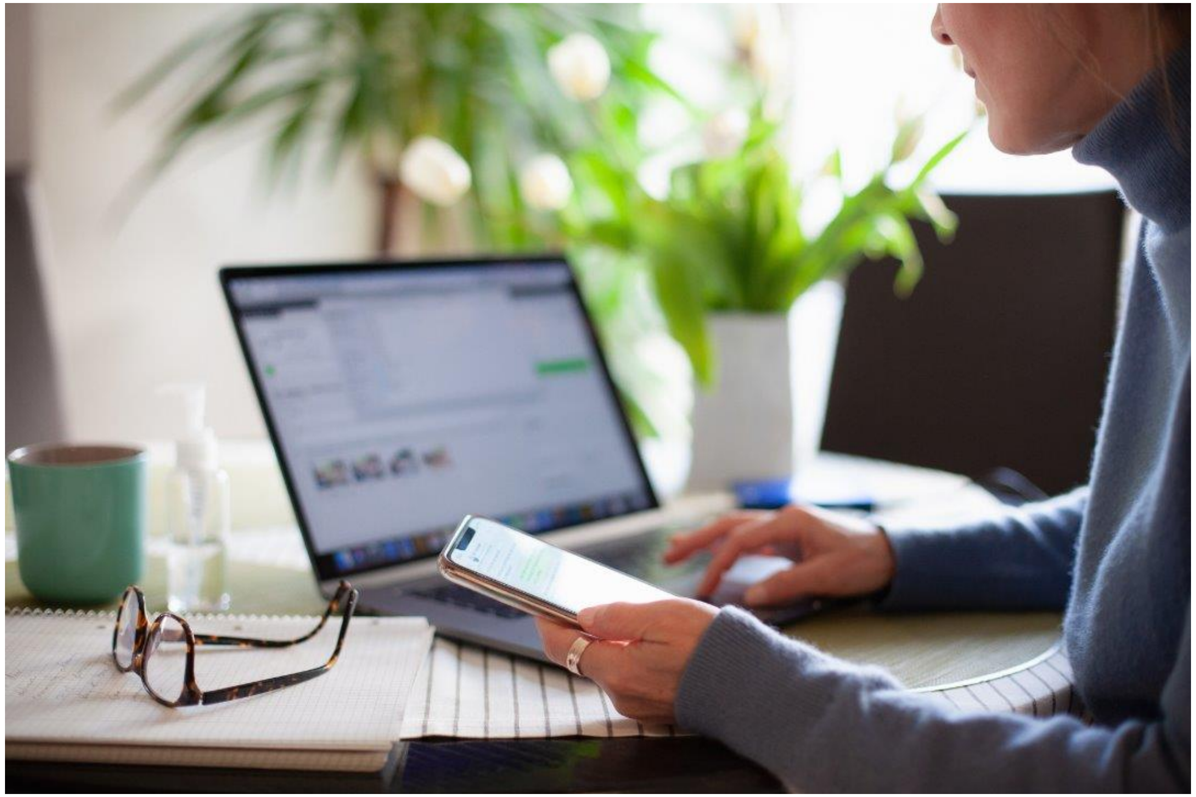
Implement

- The Code Administrator implements the final change which was decided by the Panel / Ofgem on the agreed date.



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Workgroup Responsibilities and Membership

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Expectations of a Workgroup Member

Contribute to the discussion	Be respectful of each other's opinions	Language and Conduct to be consistent with the values of equality and diversity	Do not share commercially sensitive information
Be prepared - Review Papers and Reports ahead of meetings	Complete actions in a timely manner	Keep to agreed scope	Email communications to/cc'ing the .box email

Your Roles

Help refine/develop the solution(s)	Bring forward alternatives as early as possible	Vote on whether or not to proceed with requests for Alternatives	Vote on whether the solution(s) better facilitate the Code Objectives

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Workgroup Membership

Role	Name	Alternate	Company
Proposer	Joe Colebrook		Innova Capital Limited
Workgroup Member	Brian Hoy	Steffan Jones	SP Electricity North West
Workgroup Member	Damian Clough	Edda Dirks	SSE Generation
Workgroup Member	Ed Birkett	Kate Teubner	Low Carbon
Workgroup Member	Grahame Neale	Mireia Barenys Espadaler	LightsourceBP
Workgroup Member	Helen Stack		Centrica
Workgroup Member	Jack Purchase	Ollie Easterbrook	NGED
Workgroup Member	John Brereton	Mark Harding	Enviromena
Workgroup Member	Kyle Murchie	Philip Bale	Roadnight Taylor
Workgroup Member	Mark O'Connor	Glenn Smith	EDF power solutions
Workgroup Member	Matthew Paige-Stimson	Ben Sayah	NGET
Workgroup Member	Meghan Hughes	Dimitrios Terzis	SSEN Transmission
Workgroup Member	Rob Smith	Andy Clarke	Enso Green Holdings Limited (EGHL)
Workgroup Member	Ryan Ward	Hector Perez	ScottishPower Renewables

Workgroup Membership

Role	Name	Alternate	Company
Observer	Greg Stevenson		SSEN Transmission
Observer	Leon Stafford	Will Bowen	UKPN
Observer	Natalija Zaiceva		UKPN
Observer	Patrick O'Mahony	Kevin Landers	Orsted
NESO SME	Aishwarya Harsure		NESO
Authority Representative	Chris Patrick		Ofgem

Workgroup Alternatives and Workgroup Vote

Jess Rivalland – NESO Code Administrator

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What is an Alternative Request?

What is an Alternative Request? The formal starting point for a Workgroup Alternative Modification to be developed which can be raised up until the Workgroup Vote.

What do I need to include in my Alternative Request form? The requirements are the same for a Modification Proposal you need to articulate in writing:
- a description (in reasonable but not excessive detail) of the issue or defect which the proposal seeks to address compared to the current proposed solution(s);
- the reasons why the you believe that the proposed alternative request would better facilitate the Applicable Objectives compared with the current proposed solution(s) together with background information;
- where possible, an indication of those parts of the Code which would need amending in order to give effect to (and/or would otherwise be affected by) the proposed alterative request and an indication of the impacts of those amendments or effects; and
- where possible, an indication of the impact of the proposed alterative request on relevant computer systems and processes.

How do Alternative Requests become formal Workgroup Alternative Modifications? The Workgroup will carry out a Vote on Alternatives Requests. If the majority of the Workgroup members or the Workgroup Chair believe the Alternative Request will better facilitate the Applicable Objectives than the current proposed solution(s), the Workgroup will develop it as a Workgroup Alternative Modification.

Who develops the legal text for Workgroup Alternative Modifications? NESO will assist Proposers and Workgroups with the production of draft legal text once a clear solution has been developed to support discussion and understanding of the Workgroup Alternative Modifications.

Can I vote? And What is the Alternative Vote?

To participate in any votes, Workgroup members need to have attended at least 50% of meetings. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference).

Stage 1 – Alternative Vote

- Vote on whether Workgroup Alternative Requests should become Workgroup Alternative CUSC Modifications.

- The Alternative vote is carried out to identify the level of Workgroup support there is for any potential alternative options that have been brought forward by either any member of the Workgroup OR an Industry Participant as part of the Workgroup Consultation.

- **Should the majority of the Workgroup OR the Chair believe that the potential alternative solution may better facilitate the CUSC objectives than the Original then the potential alternative will be fully developed by the Workgroup with legal text to form a Workgroup Alternative CUSC modification (WACM)** and submitted to the Panel and Authority alongside the Original solution for the Panel Recommendation vote and the Authority decision.

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Can I vote? And What is the Workgroup Vote?

To participate in any votes, Workgroup members need to have attended at least 50% of meetings. The vote shall be decided by simple majority of those present at the meeting at which the vote takes place (whether in person or by teleconference)

Stage 2 – Workgroup Vote

- 2a) Assess the original and Workgroup Alternative (if there are any) against the relevant Applicable Objectives compared to the baseline (the current code)
- 2b) Vote on which of the options is best.

Alternate Requests cannot be raised after the Stage 2 – Workgroup Vote

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Timeline

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CMP460 Timeline as of 05 November 2025

Milestone	Date	Milestone	Date
Modification presented to Panel	26 September 2025	Code Administrator Consultation (15 Business Days)	22 May 2026 – 15 June 2026
Workgroup Nominations (15 Business Days)	26 September 2025 – 17 October 2025	Draft Final Modification Report (DFMR) issued to Panel (5 Business Days)	23 July 2026
Workgroup 1 – Workgroup 6	**13 November 2025** 03 December 2025 17 December 2025 08 January 2026 15 January 2025 22 January 2026	Panel undertake DFMR recommendation vote	31 July 2026
Workgroup Consultation (15 Business Days)	27 January 2026 – 18 February 2026	Final Modification Report issued to Panel to check votes recorded correctly (Panel have 5 Business Days to check)	31 July 2026
Workgroup 7 – Workgroup 12	04 March 2026 18 March 2026 31 March 2026 10 April 2026 27 April 2026 05 May 2026	Final Modification Report issued to Ofgem (5 Business Days after Final Modification Report is issued to Panel to check votes recorded correctly)	10 August 2026
Workgroup report issued to Panel (5 Business Days)	14 May 2026	Ofgem decision	By 30 September 2026
Panel sign off that Workgroup Report has met its Terms of Reference	22 May 2026	Implementation Date	01 April 2027

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Proposer’s Presentation

Joe Colebrook, Innova Capital Limited

Connection Site Definition

14.2.5 **In general, connection assets are defined as those assets solely required to connect an individual User to the National Electricity Transmission System, which are not and would not normally be used by any other connected party (i.e. "single user assets").** For the purposes of this Statement, all connection assets at a given location shall together form a connection site.

14.2.6 Connection assets are defined as all those single user assets which: a) for Double Busbar type connections, are those single user assets connecting the User's assets and the first transmission licensee owned substation, up to and including the Double Busbar Bay; b) for teed or mesh connections, are those single user assets from the User's assets up to, but not including, the HV disconnector or the equivalent point of isolation; c) for cable and overhead lines at a transmission voltage, are those single user connection circuits connected at a transmission voltage equal to or less than 2km in length that are not potentially shareable.

14.2.7 Shared assets at a banked connection arrangement will not normally be classed as connection assets except where both legs of the banking are single user assets under the same Bilateral Connection Agreement.

14.2.8 Where customer choice influences the application of standard rules to the connection boundary, affected assets will be classed as connection assets. For example, in England & Wales NGET does not normally own busbars below 275kV, where The Company and the customer agree that NGET will own the busbars at a low voltage substation, the assets at that substation will be classed as connection assets and will not automatically be transferred into infrastructure.

Anything else is defined as Infrastructure.

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Problem Statement

Distribution customers who trigger new Supergrid Transformers (SGTs) can have costs ranging from £0-£20m, depending on the classification of the GSP they are connecting into:

- **The transmission reinforcement is free to the customer (socialised via TNUoS) if the GSP is an infrastructure site**
- **The transmission reinforcement is passed directly onto distribution customers if the GSP is a "customer site"**
  - Where there are multiple embedded generation customers triggering the works, most DNOs currently share this cost proportionally between them, although some receive price control funding to socialise those costs via DUoS.
  - Where there a demand customer triggers the works some DNOs pass the full cost onto the first demand customer, and other customers get a 'free ride'
- **DNOs aren't explicitly funded for all connections led transmission reinforcement (some is covered under DNO business plans, while the remainder is covered through customer contributions)**
- **Strategic or general infrastructure reinforcement triggered by the DNO is recovered by NESO/TOs by increasing GSP annual exit charges**

Major issues can occur if there are changes between the above charging scenarios due to additional customers contracting.

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Possible Options

1

Socialise all embedded triggered Transmission reinforcement through **TNUoS**

2

Socialise all embedded triggered Transmission reinforcement through **DUoS**

3

Pass Transmission Connection Asset Costs to Distribution Users (Baseline)

Code Change Proposal – OPTION 1

Socialise all embedded triggered reinforcement through TNUoS

- CUSC code change required. New asset classification suggestion:
  - **Embedded Shared Connection Asset** – *A Transmission Connection Asset which connects more than one embedded customer via a licensed distribution network*
- Charging rules for these assets to be aligned with those for Infrastructure Assets – i.e. funded solely via TNUoS

Benefits	Disadvantages
• Same charging mechanism now for ALL assets regardless of whether a GSP is an infrastructure site. • NESO and TOs could use existing economic assessment mechanisms to determine whether new SGTs are an economically efficient solution to prevent excess TNUoS burden. • Fairly simple CUSC Code Mod	• Disadvantages • Significant additional TNUoS Burden • Lack of locational incentive for generators to locate under less constrained GSPs

Code Change Proposal – OPTION 2

Pass through all attributable transmission works triggered by embedded customers

- CUSC code change required. New asset classification required.
    - This would impact infrastructure sites where costs are not currently passed through to embedded customers.
    - How do we manage tertiary connections?
- DCODE code change required (DCP461 in progress).

Benefits	Disadvantages
• DNOs in control of solution and could chose to deploy flex alternatives • Fairly self contained DCUSA Code Mod	• May create different charging arrangements for GSPs which are infrastructure site – no standardisation • What happens when a SGT is re-classified as an infrastructure asset because of a new tertiary connection?

Code Change Proposal – OPTION 3

Pass through Transmission Connection Asset Costs to Distribution Users

- No CUSC code change required (baseline).
- DCODE code change required (DCP461 in progress).
- DNO Connection Charging Methodology update required

Benefits	Disadvantages
• DNOs in control of solution at some GSPs and could chose to deploy flex alternatives • Self contained DCUSA Code Mod, which is not impacted by the CUSC mod	• Will create different charging arrangements for GSPs which are infrastructure site – no standardisation • What happens when a GSP is re-classified as an infrastructure site because of a new tertiary connection?

How are Infrastructure Assets charged?

- Two local components to TNUoS – these components reflect the costs of the local network.
    - Local substation, and
    - Local circuit
- These costs are only chargeable to directly connected generation.
- The Demand Tariff is applied to the demand User's average half-hourly metered demand over the three Triad periods, as described in the Statement of Use of Charging Methodology.
- Demand tariff includes an Embedded Export Tariff.
- Demand also pays a Non-locational demand residual

Therefore, new SGTs that are considered infrastructure assets are primarily paid for by directly connected generators at that substation and/or the demand residual.

NESO Charging Methodology 2025/26

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NGED DCP461

Interaction with DCP461

- CMP 460 is likely to be significantly more complex, given the potential impact on users with local service assets currently classed as infrastructure and the potential reform of TNUoS charging.
- DCP461 has a narrow scope, focused on the change to how DNOs recover the cost of transmission connection charges that are passed through to them.
- The solution approved as part of CMP460 could make the changes proposed in DCP461 obsolete, and a further DCUSA modification may be required to align the DCUSA with the CUSC once CMP460 is finalised.
- DCP461 working group agreed to develop the DCUSA modification in isolation.

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Possible Solutions – from DCP461 Consultation

- **Opti**on 1.1: no transmission costs passed through to distribution connecting customers, instead to be recovered via DUoS charges;
- Option 1.2: variant of 1.1: no transmission costs passed through to distribution connecting customers, instead to be recovered via DUoS charges, *unless* the GSP is to feed a single customer;
- **Opti**on 1.3: extend the voltage rule to transmission charges and recover more via DUoS charges; and
- **Opti**on 1.4: the application of a High-Cost Project Threshold ("HCPT") to limit recovery via DUoS charges.

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Connection cost sharing – from DCP461 Consultation

- Option 2.1 - cost apportionment;
- Option 2.2 - cost apportionment with applicability criteria;
- Option 2.3 - cost apportionment with a voltage rule applied to transmission charges; and
- Option 2.4 - the application of a High-Cost Project Threshold (“HCPT”).

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Size and Scale

- Roughly 60% of our GSPs are connection assets, whereby all asset costs are funded by distribution customers
- The cost treatment of those assets has been purposefully overlooked by Transmission Charging Review (TCR) and Significant Code Review (SCR)
- We are funded to develop/maintain these assets through New Transmission Capacity Charges (NTCC) totex allowance and Transmission Connection Point Charges (TCPC) pass through, which can be funded through existing LRE allowances or an existing Uncertainty Mechanism
- As at June 2024, we have ~ £440m of NTCC CAPEX which we have agreed to progress with the ESO, which we have passed through to customers

Solution strategy (proposed for trial)

- Current treatment doesn't explicitly agree socialisation of these costs for generation, so any generation connection triggering these works could be potentially liable for all costs. This is a massive barrier to decarbonisation.
- 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 we 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.
- We should not agree to strategic investment in all GSPs, but trigger them based on criteria – i.e. where we can credibly demonstrate the need from demand will follow soon as evidenced from our DFES and stakeholder engagement processes

Actions required for delivery

1
- The currently agreed CCCM table excludes transmission assets and needs to be rewritten
- NGED proposes the additional red rows (added below) and seeks a letter of comfort from Ofgem to progress as a trial
- Ultimately all DNOs need to agree to change the CCCM
- We would need Ofgem to agree with the changes and approve this document:

Voltage of Scheme Assets	Voltage at the POC			
	LV (below 1000V)	HV (above 1kV but less than 22kV)	EHV (above 22kV but less than 72kV)	132kV
Transmission	We fund	Apportioned (>1MW)	Apportioned	Apportioned
Transmission/132kV Substation	We fund	Apportioned (>1MW)	Apportioned	Apportioned
132kV Network	We fund	We fund[1]	Apportioned	Apportioned
132kV/ EHV Substation	We fund	EHV circuit breakers only Apportioned	Apportioned	Not applicable
EHV Network	We fund	Apportioned	Apportioned	Not applicable
132kV/ HV Substation	HV circuit breakers only Apportioned	Apportioned	Not applicable	Not applicable
EHV/HV Substation	HV circuit breakers only Apportioned	Apportioned	Not applicable	Not applicable
HV Network	Apportioned	Apportioned	Not applicable	Not applicable
HV/ LV Substation	Apportioned	Not applicable	Not applicable	Not applicable
LV Network	Apportioned	Not applicable	Not applicable	Not applicable

2 To enable the trial to proceed, NGED requests a letter of comfort from Ofgem declaring:
- It is in line with the SCR decision that transmission reinforcement for demand and generation should be socialised using the same voltage rules identified in the SCR
- NTCC can be used to fund the socialised elements of transmission reinforcement for generation. LRE mechanisms are available if this is outside DNO allowances.
- DSOs would be expected to conduct CBAs for non-wires alternatives ahead of sanctioning reinforcement and may lead to NTCC-funded flexibility markets.

3 NGED will work with the ESO/NGET to provide capacity released figures alongside each construction agreement.

Comparison of a level playing field

	Infrastructure Site	Connection Site
Wider Transmission Strategy and Costs	ESO	ESO
Local Transmission Reinforcement Strategy	ESO	DSO
Local Transmission Reinforcement Costs	ESO/TNUoS	DSO/DUoS
Transmission cost apportionment	Socialised	Recouped from individual projects
Transmission Second Comer rules	N/A	None
Distribution Reinforcement Costs	DSO/DUoS	DSO/DUoS
Distribution cost apportionment	As per CCCM	As per CCCM
Distribution Second Comer rules	As per ECCR	As per ECCR

We want this to be more like distribution reinforcement charges, which are recouped from individual projects where material, but socialised otherwise.

What are other DNOs doing?

There is a difference of approach across DNOs, some of which is due to the regional variation of DER uptake and others due to transmission voltage levels in Scotland.

NGED has the highest volume of DER seeking connection across all DNOs and double the amount of connection asset GSPs than any other DNO, so we are seeing the biggest impact.

Table 1: DNO Methodology Summary

DNO	Current Methodology	Methodology Detail
ENW	Hybrid socialisation of costs through DUoS but passing through ESO Securities.	Hybrid approach: recent situations have been **socialised through DUoS** but with ESO securities passed through to connecting customers. But would most likely charge upfront if there was only one customer triggering the work
NGED	Charged upfront to connection customers, including pass through of securities and liabilities from ESO	Where the BCA outlines work and securities/liabilities these are passed through directly to identified customers through SoW process. **Apportionment occurs based on capacity** across all users identified against the works and is revisited based on amendments to the BCA.
NPG	Charged upfront to the connecting customers	Costs are **apportioned** between customers **based upon required capacity**
SSEN	**Socialisation of costs through DUoS**, but passing through ESO Securities	**Socialisation of costs through DUoS**
SPEN	Charged upfront to connecting customers (including pass through of securities from ESO)	Costs **apportioned** between customers **based upon required capacity.**
UKPN	Charged upfront, following cost profile, to the connecting customers (as well as securitisation profile covering wider works liability)	Costs are **apportioned** between customers above 5MVA / 1MW only, **based upon required capacity** against transmission constraint, i.e. if demand transmission constraint, connecting customers with requested demand > 5MVA would share the cost of the T-work. Smaller generation not subject to Appendix G and demand <5MVA viewed as background load-growth

Other

Solution Requirements

Requirements

1. Cost (Scope) Certainty
    a. Proportional allocation as done today does not work
    b. Indicative prices very far out from delivery are subject to significant change
2. Cost Reflectivity – Paying for demand capacity required only (e.g. note the whole GSP)
3. Clear and Consistent Scope
4. Securities and Cancellation Charge – Potentially a different Mod that requires to align with the output
5. Understand the Use of System Charge impact of different scenarios
6. Send locational capacity signal?
    a. Potentially for certain technologies (e.g. can't mode a distillery)
    b. Be mindful of the bidder picture. Do not block other changes.
    c. Interaction with SSEP / CSNP / RESP (Does the latter sufficiently cover the T/D interface?)
7. Socialised up to level of the SSEP. Above this the costs are passed to the connection customer concept (potentially with cost protections for above the SSEP?)

Solution Requirements

Requirements … Continued

8. Minimise or remove the distortions seen through the current approach (e.g. relative postcode lottery)
9. Facilitate collaboration to provide the right signals for investment
   a. Assessed at NESO level
   b. Individual contracts for each customer, covering each individual site
10. Do not constrain REMA
11. Lowest overall cost
    a. System / Network Costs note these are not necessarily the same)
    b. Customer / Consumer Bills (note these are not necessarily the same)
12. Urgently remove barriers to connecting projects passing through the reformed connections process (e.g. SGT Charging itself and the downstream barriers and unintended consequences this creates)
13. Complementary to Ofgem End to End review and fill any gaps
14. Timeline – concept to certainty is crucial to investment decisions (rather than urgency of change)
15. Simplification to facilitate net zero and GB decarbonation (linked to point 8)

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Terms of Reference

Jess Rivalland – NESO Code Administrator

Terms of Reference

Workgroup Terms of Reference
a) Consider EBR implications.
b) Ensure the solution is aligned with the outcomes of the DCUSA DCP461 Workgroup and any other related DCUSA changes, where practical.
c) Consider coordination with TOs to revise construction agreements.
d) Consider alignment with end-to-end connections review.
e) Consider alignment with the wider regulatory reforms for network charging.
f) Consider the interaction with distribution and transmission business plans and the ability for TOs to secure funding for any works.
g) Consider the incentives for Users to invest efficiently, in particular with regard to the cost signals provided to Users from the charging methodology.
h) Consider the impacts of socialised costs on consumers and other parties.

Cross Code Impacts

Jess Rivalland – NESO Code Administrator

Any Other Business

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Next Steps

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