CUSC Modification Proposal Form

CMP440: Re-introduction of Demand TNUoS locational signals by removal of the zero-price floor

Overview: This CUSC modification Proposal would remove the current zero price floor from the Transmission Network Use of System (TNUoS) locational demand tariff for Final Demand, thereby re-introducing a locational investment price signal across all of Great Britian(GB). The potential for negative prices and the perverse incentive for users to consume is removed by widening the period over which consumption is measured for charging against negative tariffs.

Modification process & timetable

1. **Proposal Form**
   14 August 2024
2. **Workgroup Consultation**
   07 April 2025 – 30 April 2025
3. **Workgroup Report**
   19 June 2025
4. **Code Administrator Consultation**
   01 July 2025 – 22 July 2025
5. **Draft Final Modification Report**
   14 August 2025
6. **Final Modification Report**
   03 September 2025
7. **Implementation**
   01 April 2026

Status summary: The Proposer has raised a modification and is seeking a decision from the Panel on the governance route to be taken.

This modification is expected to have a: High impact

Suppliers

Proposer's recommendation of governance route	Standard Governance modification with assessment by a Workgroup	
Who can I talk to about the change?	**Proposer:** Lauren Jauss Lauren.jauss@rwe.com 07825 995497	**Code Administrator Contact:** Cusc.team@nationalgrideso.com Code Administrator

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What is the issue?

Missing Locational Demand Signal

A zero price floor was applied to TNUoS locational demand tariffs from April 2023, removing most of the demand investment locational price signal, as a consequence of implementing CMP343. This previous modification gave effect to Ofgem's decision from the Targeting Charging Review by levying Transmission Demand Residual (TDR) as a fixed annual site charge, instead of on a £/kW basis.

Before April 2023, demand tariffs included a locational signal that was broadly equal and opposite to the generation locational signal i.e., in the same way that generation tariffs are mostly positive and, in some locations, negative; the opposite was true for locational demand tariffs. Transmission Demand Residual (TDR) and locational demand charges, both in £/kW, were previously added together. This resulted in £/kW charges to demand that were positive in all demand charging zones. However, when the TDR was removed from the £/kW charge, the negative locational tariffs in some zones, based on demand measured over a narrow period in time, might have outweighed all other electricity costs, providing a perverse incentive to users by paying them to increase their consumption for those periods.

Hence the zero price floor was applied on implementation of CMP343. The loss of the locational demand signal was recognised as an undesirable consequence and a new defect. WACMs were raised that proposed introducing regional variations to TDR charges to address this. However, Ofgem decided this had the potential to introduce a distortion to TDR. Further work was required.

Under existing methodology, the objective of any measurement of consumption should be to extrapolate to the expected consumption at Average Cold Spell (ACS) Peak

The Proposer believes the current methodology considers the Year Round Background scenario (with demand at ACS Peak) as a proxy for the Economy Criterion which in principle takes into account the cost of constraints across the year and their impact on the need for transmission investment. A consumer's ACS Peak consumption is equivalent to generator TEC.

The Proposer believes that having taken into consideration the optimal transmission build versus annual constraints costs, the Year-Round Background scenario is designed to represent the optimal maximum flow scenario where 1MW of incremental demand or generation would trigger transmission build to accommodate that 1MW flow.

The Year-Round Background represents ACS conditions, which are the median expected demand for the highest peak period in a single year. However, levying demand TNUoS charges on a small number of periods of peak consumption, such as Triads, is not appropriate in negative charging zones due to the reasons described above.

Project TransmiT predominantly focused on generation, allocating costs associated with each background to different technologies depending on the likelihood that different generating technologies would affect required network investments in either background. Analysis by the then National Grid for CMP213: Project TransmiT TNUoS Developments (which introduced the Sharing approach), showed that a generator's Annual Load Factor generally has a linear relationship with its impact on incremental annual constraint costs. The follow-on relationship between annual constraints costs and transmission investment

requirements was not demonstrated but was deemed to also be linear due to the convergence of the Long-Run Marginal Cost (LRMC) and the Short-Run Marginal Cost (SRMC) on average over the long term where the transmission network is planned using the cost benefit analysis. There were concerns at the time of the development and implementation of CMP213, that the Annual Load Factor (ALF) approach was too simplistic. However, the resulting solution essentially scales down charges to account for the shared use throughout the year of Year-Round transmission circuits across zone boundaries.

Whilst the Economy Criterion and Year-Round Tariffs are meant to represent year round constraints and resulting long term investment requirements, there has not been any analysis done to establish the relationship between a consumer's network use across the year compared with their ACS Peak network use to assess the suitability of the Year Round Background proxy and adjust resulting tariffs accordingly. The Proposer believes it is unlikely that demand users currently "share" the network to the same degree as generators. For the moment, ACS Peak consumption remains the "right" benchmark for charging for demand against both backgrounds.

The wider the consumption measurement period, the less accurately a consumers ACS Peak Demand can be estimated for charging

The current approach for consumption is to measure metered demand:

- At Triads for half hourly (HH) customers
- 4-7pm all year for non-half hourly (NHH) customers.

For NHH customers, ESO use forecasts of triad demand versus consumption 4-7pm all year to convert the £/kW tariff at ACS Peak to an equivalent p/kWh tariff over the period of measured consumption. The same conversion "factor" is used for all NHH customers in each zone, implicitly making the assumption that all NHH users in that zone have the same demand profile. This means that customers with a peakier Profile Class pay relatively less in £/kW for their ACS Peak consumption than those with a flatter profile class.

Therefore, if ACS Peak is the "right" benchmark for charging, moving to a wider measurement period is less accurate. Hence for those zones where charges are above the floor, moving to a wider measurement period would be less cost reflective. However, for those zones where charges are zeroed out due to the floor, a wider measurement period would be better than essentially no measurement and no charge, or rather incentive, at all.

Why change?

Ofgem published their decision on CMP343 in March 2022, by which time they had already announced their decision to launch the TNUoS Taskforce which was expected to review demand charges, particularly locational signals.

In their March 2024 meeting, the TNUoS Taskforce agreed there was high priority case for change to the demand locational tariff floor. They noted the importance of investment signals for demand cited in DESNZ's Second Consultation on the Review of Electricity Market Arrangements (REMA) in driving new industrial investment and economic growth in areas with high levels of renewable generation, and in ESO's Beyond 2030 report that

recommended that demand for electricity be placed closer to where it is produced to reduce congestion across the system. Both were also published in March 2024.

The Taskforce also agreed with Ofgem's view, which is stated in their September 2023 Open Letter on Strategic Charging Reform, that signals sent through TNUoS should solely seek to influence the investment decisions of system users and not real-time operation. In their consideration of wider charging periods to remove the demand floor, the key questions the Taskforce noted were:

1. Should the peak charge apply to winter or all year?
2. Should the year-round charge apply all day or just 4-7pm?
3. Should positive and negative demand charges be charged differently i.e., keep the existing methodology for positive demand charges?
4. What should the methodology be for conversion from £/kW to p/kWh? (Noting that it may have a practical impact on the above design choices)

What is the proposer's solution?

The proposed solution is for negative demand TNUoS charges to be levied on actual consumption over a broader base of hours for both Peak and Year-Round demand tariffs in order to reduce the operational TNUoS signal and to remove the current zero demand floor. A wider charging period reduces, if not removes, the probability that negative locational TNUoS charges outweigh all other delivered electricity costs to consumers during those periods over which TNUoS is levied. A conservative approach should be taken in the conversion from £/kW to p/kWh equivalent tariffs.

The four types of TNUoS charge that are currently levied on licenced suppliers are:

1. Locational £/kW charges levied on half hourly (HH) metered demand as "Chargeable Demand Locational Capacity" over the Triad periods.
2. Locational p/kWh charges levied on non-half hourly (NHH) as "Chargeable Energy Capacity" annual consumption between 4pm-7pm daily throughout the year.
3. A locational £/kW Embedded Export Tariff (EET) credit for embedded generation over the Triad periods
4. TDR (Final Demand only) levied on a £/site/day basis, with pricing bands for different ranges of total annual consumption.

As SMART meters continue to be rolled out and the Market Wide Half Hourly Settlement programme is implemented, an increasing number of NHH customers will become HH customers.

All 1-3 locational tariffs above are currently subject to a zero-price floor.

Generators are also currently liable for Demand TNUoS if they consume over the charging period. If this is widened, the current arrangements would start to capture generator consumption. This would not be appropriate, as consumption over the wider charging period would not be a good proxy for assuming an increased amount of consumption would occur during the peaks, as obviously the opposite is true.

TNUoS charges for distribution connected generators and storage demand are not intended to be in scope of this modification, as these are to be considered separately by Ofgem with recommendations from the Distributed Generation Sub-group of the TNUoS Taskforce, and by the new Storage TNUoS Sub-group. The EET described in number 3 above is similarly out of scope of this proposal.

The Proposer therefore believes that Final Demand is a suitable categorisation of existing network users to which the following proposed changes should apply.

The Proposer also believes that the locational signals that this modification re-introduces should apply to electrolysers as an important future source of demand that can respond to long term locational cost signals to some extent. It is not clear at this stage whether electrolyser demand will be included in the definition of Final Demand. If excluded, the Proposer believes that the definition of users to whom these charges are extended should be revisited so as to include electrolysers.

Therefore, it is proposed that:

- The zero price floor be **removed for Final Demand for negative Peak** Tariffs and those negative charges are levied on both HH and NHH metered energy consumption over the period 16:00 hrs to 19:00 hrs inclusive every day over the Financial Year i.e. in the same way as NHH consumption is currently charged.
- The zero price floor be **removed for Final Demand for negative Year Round Tariffs** and those negative charges are levied on both HH and NHH total annual metered energy consumption.
- The corresponding **negative tariffs in p/kWh are arrived at by scaling the corresponding £/kW Demand Locational Tariff by the ratio of forecast metered consumption over the relevant period** assuming a baseload consumption profile. In this way the negative charge will always be based on an underestimate of ACS Peak consumption.

Summary

Current Locational Chargeable (Energy) Capacity for Final Demand:

	Positive Charges		Negative Charges	
	HH	**NHH**	**HH**	**NHH**
Peak	Triad	4-7pm all year	Zero	Zero
Year Round	Triad	4-7pm all year	Zero	Zero

Proposed Locational Chargeable (Energy) Capacity for Final Demand:

	Positive Charges		Negative Charges	
	HH	**NHH**	**HH**	**NHH**
Peak	Triad	4-7pm all year	4-7pm all year	4-7pm all year
Year Round	Triad	4-7pm all year	All year	All year

Draft legal text

Legal text will be developed during the Workgroup process.

Proposer's assessment against CUSC Charging Objectives	
Relevant Objective	**Identified impact**
(a) 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** Would re-introduce a cost-reflective incentive resulting in more efficient demand investment
(b) 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 C26 requirements of a connect and manage connection);	**Neutral** Will not impact cost recovery but will reduce socialisation of charges and instead re-distribute charges between demand users to be more reflective of their relative cost impact on the transmission system.
(c) That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;	**Positive** Would improve cost-reflectivity of charges so they are more representative of the impact on transmission investment requirements.
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	**Neutral** No impact. Re-introduces a cost signal that was in place before April 2023.
(e) Promoting efficiency in the implementation and administration of the system charging methodology.	**Positive** Removal of the zero priced floor results in better alignment between positive and negative charging zones.
**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	Positive Consumers locating closer to generation are likely to have a greater reliability of supply from the system.
Lower bills than would otherwise be the case	Positive More cost-reflective charges result in more cost efficient investment overall.
Benefits for society as a whole	None
Reduced environmental damage	Positive Less network is required to be built.
Improved quality of service	None

When will this change take place?

Implementation date
April 2026 (adequate time is required for suppliers to anticipate changes to customer tariffs including the default tariff cap)

Date decision required by
30 September 2025

Implementation approach
Customer consumption over which charges are levied will need to be measured over a different period, and total Wider Tariff revenue collection will change, also impacting Transmission Demand Residual charges.

Proposer's justification for governance route
Governance route: Standard Governance modification with assessment by a Workgroup

This modification will have a high impact on Suppliers in particular and some further analysis will be required.

Interactions

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

This modification should be consistent with the principles of the SQSS.

Acronyms, key terms and reference material

Acronym / key term	Meaning
ACS	Average Cold Spell
ALF	Annual Load Factor
BSC	Balancing and Settlement Code
CMP	CUSC Modification Proposal
CUSC	Connection and Use of System Code
DESNZ	Department of Energy Security and Net Zero
EBR	Electricity Balancing Regulation
EET	Embedded Export Tariff
HH	Half hourly
NHH	Non Half-Hourly
LRMC	Long Run Marginal Cost
REMA	Review of Electricity Market Arrangements
SRMC	Short Run Marginal Cost
STC	System Operator Transmission Owner Code
SQSS	Security and Quality of Supply Standards
T&Cs	Terms and Conditions
TDR	Transmission Demand Residual
TEC	Transmission Entry Capacity

Reference material

- Ofgem's decision from the Targeting Charging Review
- CMP343 Transmission Demand Residual bandings and allocation for 1 April 2022 implementation:
- CMP213 Project TransmiT TNUoS Developments:
- TNUoS Taskforce January 2024 meeting Frontier Demand TNUoS qualitative analysis
- TNUoS Taskforce March 2024 meeting high priority case for change to the demand locational tariff floor
- DESNZ's Second Consultation on the Review of Electricity Market Arrangements (REMA) in driving new industrial investment and economic growth in areas with high levels of renewable generation
- ESO Beyond 2030 report

[1] If your modification amends any of the clauses mapped out in Exhibit Y to the CUSC, it will change the Terms & Conditions relating to Balancing Service Providers. The modification will need to follow the process set out in Article 18 of the Electricity Balancing Guideline (EBR – EU Regulation 2017/2195) – the main aspect of this is that the modification will need to be consulted on for 1 month in the Code Administrator Consultation phase. N.B. This will also satisfy the requirements of the NCER process.