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Workgroup Report		
<h1>CMP440: Re-introduction of Demand TNUoS locational signals by removal of the zero-price floor</h1>		<h2>Modification process &amp; timetable</h2>
<p><b>Overview:</b> This Connection and Use of System Code (CUSC) modification proposes removing 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 Britain (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.</p>		<div>1</div> <div>Proposal Form</div> <div>14 August 2024</div>
		<div>2</div> <div>Workgroup Consultation</div> <div>10 July 2025 – 31 July 2025</div>
		<div>3</div> <div>Workgroup Report</div> <div>22 January 2026</div>
		<div>4</div> <div>Code Administrator Consultation</div> <div>09 February 2026 – 03 March 2026</div>
		<div>5</div> <div>Draft Modification Report</div> <div>19 March 2026</div>
		<div>6</div> <div>Final Modification Report</div> <div>09 April 2026</div>
		<div>7</div> <div>Implementation</div> <div>01 April 2027</div>
<p><b>Have 10 minutes?</b> Read our <a href="#">Executive summary</a></p> <p><b>Have 40 minutes?</b> Read the full <a href="#">Workgroup Report</a></p> <p><b>Have 60 minutes?</b> Read the full Workgroup Report and Annexes.</p>		
<p><b>Status summary:</b> The Workgroup have finalised the Proposer’s solution as well as 1 alternative solution. They are now seeking approval from the Panel that the Workgroup have met their Terms of Reference and can proceed to Code Administrator Consultation.</p>		
<p><b>This modification is expected to have a: High</b> impact on Suppliers.</p>		
<b>Governance route</b>	Standard Governance modification with assessment by a Workgroup.	
<b>Who can I talk to about the change?</b>	<p><b>Proposer:</b> Lauren Jauss, RWE</p> <p><a href="mailto:Lauren.jauss@rwe.com">Lauren.jauss@rwe.com</a></p> <p>Phone: 07825 995497</p>	<p><b>Code Administrator Chair:</b> Kat Higby</p> <p><a href="mailto:katharine.higby@neso.energy">katharine.higby@neso.energy</a></p>

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## Contents

Executive Summary.....	3
What is the issue? .....	5
What is the defect the Proposer believes this modification will address? .....	5
Why change? .....	8
What is the solution? .....	9
Proposer's original solution after amendment during Workgroup phase:.....	9
Workgroup Alternative 1 solution after discussion and clarification during Workgroup phase	14
Legal text.....	24
Workgroup considerations .....	25
Workgroup Discussion ahead of the Workgroup Consultation .....	25
Workgroup Consultation Summary .....	41
Post Consultation Workgroup Discussion .....	43
Alternative Requests.....	47
Terms of Reference Overview .....	49
What is the impact of this change? .....	50
Original and Workgroup Alternative Proposer's assessment against Code Objectives.....	51
Workgroup Vote.....	53
When will this change take place? .....	54
Interactions .....	54
Acronyms, key terms and reference material.....	55
Annexes.....	58

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## Executive Summary

CMP440 proposes to remove the zero-price floor from Transmission Network Use of System (TNUoS) locational Demand tariffs for Final Demand, reintroducing a locational investment price signal across Great Britain. This change was raised to address the loss of locational signals caused by previous reforms, which removed incentives for Demand to locate in areas that reduce Transmission costs and congestion.

### What is the issue?

The zero-price floor applied to TNUoS locational Demand tariffs since April 2023 has removed locational investment signals for Demand, especially in Northern zones of Great Britain, eliminating incentives for Users to locate in areas that reduce Transmission costs and congestion.

Previously, Demand tariffs included locational signals that balanced generation signals, but reforms led to uniform charges and the loss of these signals. This has created concerns about inefficient consumption incentives and the need to restore cost-reflective locational signals for Demand.

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

**Proposer's solution:** Remove the zero-price floor from Final Demand TNUoS locational Demand tariffs and levy negative Demand charges on actual energy consumption (total kilowatt-hour (kWh)) over 4–7pm all year for both Peak and Year-Round Tariffs, aiming to restore locational investment signals without incentivising unhelpful consumption at times of high national Demand. This approach broadens the charging period to reduce the risk of creating an incentive to waste energy produced from non-low carbon sources and applies only to Final Demand, excluding Non-Final Demand such as storage and Power Station Demand.

**Implementation date:** 01 April 2027

### Summary of potential alternative solutions and implementation date:

#### Alternative Request 1:

This alternative solution is different to the original in two ways:

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1. In zones where the total Demand locational signal is negative, a p/kWh tariff is charged across total annual Demand rather than 4-7pm only.
2. In each negative charging zone, a single common rate is calculated for Non-Half Hourly (NHH) and Half Hourly (HH), rather than a different p/kWh rate for each.

The alternative was voted in by the Workgroup and became Workgroup Alternative CUSC Modification 1 (WACMI).

**Implementation date:** 01 April 2027

## What is the impact if this change is made?

If approved, this modification will change how Suppliers and directly connected Demand Users are charged for TNUoS from 01 April 2027, particularly affecting those in the North of Britain by allowing negative locational charges to be passed through as credits instead of being set to zero. This will also require an increase in the Transmission Demand Residual (TDR) charge element for all bands or classes of Demand customers to maintain revenue neutrality, while retaining the Triad<sup>1</sup> charging basis for zones with positive charges.

**Workgroup conclusions:** The Workgroup concluded by majority that the original and WACMI better facilitated the Applicable Objectives than the Baseline.

## Interactions

This modification should be consistent with the principles of the Security and Quality of Supply Standard (SQSS). This modification was raised following discussions at the TNUoS Charging Task Force.

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<sup>1</sup> is used as a shorthand way to describe the three Settlement Periods of highest Transmission systems Demand, namely the half hour Settlement Period of system peak Demand and the two half hour Settlement Periods of next highest Demand, which are separated from the system peak Demand and from each other by at least 10 Clear Days, between November to February inclusive

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## What is the issue?

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

#### **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 'Transmission Demand Residual Bandings and Allocation for April 2022 Implementation'. This previous modification gave effect to Ofgem's decision from the Targeted Charging Review by levying TDR as a fixed annual site charge per charging band, instead of on a fixed £/kW national basis levied at time of Triads.

Before April 2023, Demand tariffs included a locational signal that was derived from nodal tariffs output from the Transport Model which are equal and opposite to the same generation nodal tariffs. E.g. where generation tariffs are highly positive, Demand tariffs are negative and vice versa. TDR and locational Demand charges, both in £/kW, were previously added together, resulting in £/kW charges to Demand that were positive in all Demand charging zones. However, when the TDR was removed from the £/kW charge and started to be recovered on a different basis, the negative locational £/kW tariffs in some Northern zones would, without the "floor", no longer have been "masked" by the positive TDR offset to them (from April 2023).

Because of the Triad charge being based on Demand measured over a very narrow period of time, the negative charge (i.e. the credit) might have outweighed all other electricity costs in relation to each site, providing an unhelpful incentive to Users by paying them to increase their consumption for those peak periods.

The zero price floor on zonal Demand locationals was introduced as part of the design and implementation of CMP343. It is applied to the p/kWh value of the NHH TNUoS Demand locationals, which are recovered on the basis of cumulative Demand across the period 4pm–7pm, as well as to the £/kW value of Triad-based HH TNUoS Demand locationals. The resulting loss of the locational Demand signal in the North of Great Britain (GB) (zones 1 to 7 at present) was believed by some to represent an undesirable consequence, and a new defect. WACMs were raised against CMP343 that proposed introducing regional variations to TDR charges to address this. However, Ofgem decided they had the potential to introduce a distortion to TDR. In their decision

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letter, Ofgem noted “Of the options available, we consider floor at 0 best meets the fairness principle. We do note that the potential distortion for NHH consumers is not as significant as that for HH consumers. As noted above, industry parties may wish to make proposals for a differential approach between HH and NHH consumers. We would expect parties to demonstrate how such an approach might better facilitate the Applicable CUSC Objectives (ACOs)”. Further work was therefore required.

Under the existing methodology, the Proposer believes the objective of any measurement of consumption is to apportion to the expected consumption at Average Cold Spell (ACS) peak. The proposal is consistent with this.

The Proposer believes the current methodology considers that CMP213, also known as Project TransmiT, introduced the “year-round” background scenario into TNUoS charging (with Demand at ACS peak) as a proxy for what is known as the “Economy Criterion” in the SQSS. In principle this 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 Transmission Entry Capacity (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 1 Megawatt (MW) of incremental Demand or generation would trigger Transmission build to accommodate that 1MW flow.

The year-round background represents ACS conditions, which is 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 in 2013 by the then National Grid for Project TransmiT TNUoS Developments (which introduced the “sharing” approach), showed that a Generator’s Annual Load Factor (ALF) 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

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but was deemed to also be linear due to the convergence of the Long Run Marginal Costs (LMRC) and the Short Run Marginal Costs (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 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, the Proposer is not aware of 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. Nor would it be easy to categorise different sorts of Demand Users, for example, in the way that CMP213 categorised Generators, for the differential generation TNUoS charging that it introduced. 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 consumer's ACS peak Demand can be estimated for charging.

The current approach for consumption is to measure metered Demand:

- At Triads for HH customers
- 4-7pm all year for NHH customers.

For NHH customers, National Energy System Operator (NESO) uses 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.



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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 (i.e. are inherently positive), 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 negative charge.

## 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 Department of Energy Security and Net Zero (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 NESO’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 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 to all of the year?
2. Should the year-round charge apply all day or just to 4-7pm?
3. Should positive and negative Demand charges be charged differently i.e. should the existing methodology for positive Demand charges be retained?
4. What should the methodology be for conversion from £/kW charges to p/kWh? (Noting that it may have a practical impact on the above design choices)



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## What is the solution?

### Proposer's original solution after amendment during Workgroup phase:

The four types of TNUoS charge that are currently levied on licensed Suppliers are:

5. Locational £/kW charges levied on HH metered Demand as "Chargeable Demand Locational Capacity" over the Triad periods.
6. Locational p/kWh charges levied on NHH as "Chargeable Energy Capacity" annual consumption between 4pm–7pm daily throughout the year.
7. A locational £/kW Embedded Export Tariff (EET) credit for embedded generation over the Triad periods
8. 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 (MHHS) programme is implemented, some existing NHH customers will be charged on the basis that HH customers are currently charged and vice versa, as illustrated in the table below (extracted from the CMP430 Final Modification Report found [here](#)).

Domestic Premises Indicator	Connection Type Indicator	Current Measurement Class (non-MHHS)	Charging Arrangement Pre- MHHS Transition	Charging Arrangements post MHHS Transition
Domestic (T)	W (Whole Current);	A	Chargeable Energy Capacity	Chargeable Energy Capacity
	L (LV with Current Transformer);	F	Chargeable Energy Capacity	Chargeable Energy Capacity
	H (HV with Current Transformer) or	C	Chargeable Demand Locational Capacity	Chargeable Energy Capacity
	E (EHV with Current Transformer)	B *	Chargeable Energy Capacity	Chargeable Demand Locational Capacity
Non-Domestic (F)	U (Unmetered)	G	Chargeable Energy Capacity	Chargeable Energy Capacity
	W (Whole Current)	A	Chargeable Energy Capacity	Chargeable Energy Capacity
	L (LV with Current Transformer)	C	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
		E	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
		A	Chargeable Energy Capacity	Chargeable Demand Locational Capacity
	H (HV with Current Transformer)	C	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
		E	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
		A	Chargeable Energy Capacity	Chargeable Demand Locational Capacity
	E (EHV with Current Transformer)	C	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
		E	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity
	U (Unmetered)	D	Chargeable Demand Locational Capacity	Chargeable Demand Locational Capacity

Chargeable Demand Locational Capacity = Triad  
Chargeable Energy Capacity = 4pm – 7pm

Yellow highlight shows change in TNUoS charging as a result of CMP430

Historically, Suppliers were billed locational TNUoS on their NHH customers profiled, rather than actual usage 4–7pm. There was no reason for Suppliers to design time of

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use tariffs that encourage NHH customers to shift their usage, as it would not impact the locational TNUoS billed. As a result, negative p/kWh tariffs over evening peak, would not be expected to impact NHH Users actual Demand usage patterns.

However, with the increasing adoption of smart meters, Suppliers' locational TNUoS bill will be increasingly based on their NHH customers *actual* usage over 4-7pm, with time of use tariffs able to pass costs or savings on to customers. Therefore, there is an increasing possibility that NHH will be respond to time based locational price signals, so an increased importance in adopting the right charging period base.

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

The proposed solution as amended during Workgroup stage is for negative Demand TNUoS charges to be levied on actual consumption over a broader base of hours than Triads, namely 4-7pm, for both Peak and Year-Round Demand Tariffs alike, in order to reduce the operational TNUoS signal in spite of the proposal also entailing removal of the current zero Demand floor. A wider charging period would reduce, if not remove, the probability that negative locational TNUoS charges outweigh all other delivered electricity costs to consumers during those periods over which TNUoS is levied.

Whilst initially it had been proposed that a conservative approach should be taken to the conversion from £/kW to p/kWh equivalent tariffs so that charges did not over-incentivise Demand Users to locate in negative charging zones, this was amended and the new conversion uses the same average, unbiased as used in baseline CUSC.

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. The Proposer believes 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. The Proposer's solution also maintains the floor, preventing negative Demand locational charges, for storage and other Non-Final Demand.

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 3 above is similarly out of scope of this proposal.

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The Proposer therefore believes that Final Demand as defined in baseline CUSC, is a suitable categorisation representing the only class of existing network Users to which the modification's proposed changes should apply.

Summary of the proposal:

- Both Peak and Year-Round Tariffs would be levied 4–7pm all year for both HH and NHH Final Demand customers in negative charging zones; and
- Negative tariffs in p/kWh are arrived at by scaling the corresponding £/kW Demand Locational Tariff by the forecast total Grid Supply Point (GSP) metered consumption over the charging period divided by total GSP peak consumption (i.e. using the weighted average profile, as in baseline CUSC).

The Proposer also noted that following transition to MHHS, the classification of customers as HH and NHH can be misleading when referring to their billing treatment in a TNUoS context. Any reference in this modification to “HH customers” means those customers on which TNUoS charges are currently levied based on chargeable Demand locational capacity, and references to “NHH customers” mean those customers on which TNUoS charges are currently levied based on chargeable energy capacity.

### **Reason for levying both charges 4–7pm All Year**

The Workgroup considered the new tariff tables that would be required for the initial original proposal. Currently, under the baseline CUSC, only two columns are required per GSP zone: one £/kW tariff levied over Triad for HH customers, and one p/kWh tariff levied over 4–7pm all year on NHH customers. However, under the initial original proposal, four additional columns (six in total) would have been required to account for charges in negative charging zones. The additional columns are:

1. p/kWh Peak tariff levied on HH customer consumption 4–7pm all year round
2. p/kWh Year-Round Tariff levied on HH customer consumption all periods all year round
3. p/kWh Year-Round Tariff levied on NHH customer consumption all periods all year round
4. £/kW total tariff levied at Triad on Non-Final Demand (which is different to Final Demand tariff levied at Triad when the Peak Tariff only is negative)

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The Proposer considers the new tariff tables to be highly complex for industry parties to understand and use and believes that simplifying them would significantly improve the solution. If both peak and year-round were levied on the same basis, there would be no reason to split out the two tariff elements and charge them separately, and there would be fewer permutations of charges since there is no need to consider the scenario where one tariff element is positive, and the other is negative.

The updated original solution would therefore only require a total of three columns of different tariffs:

1. £/kW total tariff levied according to their take at Triad half hours, on HH customers and Non-Final Demand in positive charging zones.
2. p/kWh total tariff levied on HH customer consumption in negative zones 4-7pm all year.
3. p/kWh total tariff levied on NHH customer consumption in both positive and negative zones 4-7pm all year.

The Proposer had also further considered whether there is a case for charging year-round to Demand in the same way as it is charged to generation, i.e. all year, and decided that there is not. Generation is charged on the basis of TEC, and generation year-round charges are scaled down to different degrees by ALF to account for the fact that the network is shared throughout the year with other technology classes. However, Demand sharing does not feature as a concept in the methodology and existing positive charges are levied based on Triad Demand, or derived from forecast Triad Demand, as a proxy for generation TEC, and sharing is not applied. Therefore, the Proposer has concluded that charging all Users the Year-Round Tariff 4-7pm is indeed better than levying on consumption all year because the measurement of consumption for these purposes seeks to establish a parallel for TEC, not ALF. The Proposer believes that consumption measured 4-7pm will be a better proxy for Triad consumption which is the basis for levying both tariffs.

### **Reason for using the Weighted Average Profile instead of assuming baseload**

The Proposer considered whether it was better to be conservative or not when using 4-7pm consumption as a proxy for Triad consumption. If all Demand is assumed to be baseload, the number of customers that are “over-incentivised” to locate in negative charging zones would be minimal. This means a relatively low p/kWh tariff is derived that assumes the rate of offtake during the charging period is the same as the rate of

## Public

offtake during Triad. If this approach is taken, then only those consumers with a higher forecast rate of average offtake across the 4-7pm period all year, compared with their offtake during the Triad, would be over-incentivised.

The Proposer concluded that whilst being conservative and providing some incentive was better than no incentive under the baseline floored approach, the best approach would be to use a best estimate and not a conservative view. This is because the Proposer concluded that under-incentivising is as undesirable as over-incentivising, and an average approach balancing over- and under-incentivisation would minimise the average error.

## Summary of Charging Periods

**Table 1 – Current Baseline Charging Periods for Final Demand**

	Positive Charges		Negative Charges	
	HH	NHH	HH	NHH
<b>Peak</b>	Triad	4-7pm all year	Zero	Zero
<b>Year Round</b>	Triad	4-7pm all year	Zero	Zero

**Table 2 – Initial Original Proposal's Charging Periods for Final Demand**

	Positive Charges		Negative Charges	
	HH	NHH	HH	NHH
<b>Peak</b>	Triad	4-7pm all year	<b>4-7pm all year</b>	<b>4-7pm all year</b>
<b>Year Round</b>	Triad	4-7pm all year	<b>All year</b>	<b>All year</b>

**Table 3 – Updated Original Proposal's Charging Periods for Final Demand**

	Positive Charges		Negative Charges	
	HH	NHH	HH	NHH
<b>Peak</b>	Triad	4-7pm all year	4-7pm all year	4-7pm all year
<b>Year Round</b>	Triad	4-7pm all year	<b>4-7pm all year</b>	<b>4-7pm all year</b>

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## Workgroup Alternative 1 solution after discussion and clarification during Workgroup phase

For TNUoS zones where the total Demand locational signal is negative, locational TNUoS is converted into a p/kWh figure and charged over total Demand across all periods. The same rate applies to NHH and HH. Full calculation of indicative charges can be found in **Annex 06**, but the calculated tariffs are summarised below:

Demand Zone		2026/27 CMP440 WACMI		
		HH Triad (£/kW)	NHH 4-7 (p/kWh)	All Periods HH + NHH (p/kWh)
1	Northern Scotland	-		-0.79
2	Southern Scotland	-		-0.59
3	Northern	-		-0.26
4	North West	-		-0.11
5	Yorkshire	-		-0.10
6	N Wales & Mersey	-		-0.04
7	East Midlands	-		-0.00
8	Midlands	3.77	0.51	
9	Eastern	0.65	0.09	
10	South Wales	6.05	0.74	
11	South East	5.44	0.78	
12	London	7.06	0.76	
13	Southern	8.26	1.12	
14	South Western	13.92	2.02	
Demand residual £m		Impact on demand residual	2.86%	

This approach spreads the negative charge across all a consumer's Demand, removing any incentives to shift Demand to peak periods to capture lower effective prices.



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The overall amount allocated is the same as the Proposer's solution – and is dictated by the output of the TNUoS Model. This alternative proposes using a similar approach to converting to p/kWh as is currently used for positive NHH charging but spreads the credit overall Demand (not just peak) to avoid unintentional signals. This can be summarised as:

**Zones with positive locational TNUoS HH:** Directly use the £/kW figure generated by the TNUoS model (current method does not change).

**Zones with Positive locational TNUoS NHH:**  $\text{£/kW (from model)} \times \text{NHH TNUoS Model Zonal Demand} / \text{NHH forecast zonal annual Demand across 4-7pm}$ .

(current method used to convert to p/kWh does not change)

**Zones with negative locational TNUoS HH and NHH:**  $\text{£/kW (from model)} \times \text{Total TNUoS model Zonal Demand} / \text{Total forecast zonal annual Demand across all periods}$ .

(New – converts to a year-round total p/kWh Demand spread across all annual Demand in negative zones)

*The TNUoS model Demand = is the Demand used in the TNUoS model, which only uses Demand at peak as an input (a model simplification).*

## Rationale for WACMI solution

The WACMI Proposer believes that with negative credits of over £100/MWh over the peak 4-7pm in some zones by 2030, the Proposer's original solution would result in a strong distortive signal for Demand in Scotland to increase over or shift to a large number of peak Settlement Periods, historic analysis of Elexon data was presented to support this view.

The WACMI Proposer also believes that the solution better facilitates the CUSC Applicable Objectives, in that it is much more reflective of the actual costs that drive Transmission investment in negative charging zones – i.e. periods of constraint or high wind, not peak Demand.



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The WACMI Proposer raised the analysis in the TNUoS Task Force presentation by Frontier Economics. This highlighted that costs associated with year-round circuits are driven by periods of constraints and recommended that year-round charging move to either all Demand (simple but still more reflective than charging over peak), or over periods of constraints (more reflective, but more complicated). The Proposer of WACMI presented extracts from the Clean Power 30 Action Plan, highlighting that the £60bn infrastructure spend needed was economically framed as required to avoid increasing constraint costs. The Proposer highlighted that ~95% of the locational TNUoS charges in negative Demand TNUoS zones related to year-round circuits

## Frontier Economics Background Scenario Analysis

The original Proposer sets out in the Background Analysis section of this report that modelling from Frontier Economics in 2023 to test the validity of the existing TNUoS backgrounds supports ACS peak Demand as being the conditions that drive network expansion for all circuits, including year-round circuits.

The WACMI Proposer does not believe this is what the analysis shows, and in any case believes it is important to understand the limitations of the analysis.

Limitations of modelling included:

- (i) Neither the Dispatch Model, or the Transport Model used were made available to the Workgroup.
- (ii) Detailed inputs or results were not published, only a summary
- (iii) Only conditions from the Dispatch Model in 96 hours (~1%) out of a full year were selected to test as a background in the Transport Model, and the max/min flows were all calculated with respect to these 96 hours.
- (iv) The choice of 90% of maximum observed flows a 'representative' is arbitrary: if 85% were chosen, more circuits would be considered representative under each background tested, and if 95% were chosen, fewer would.
- (v) The analysis compares the number of circuits, not weighted by megawatt-kilometre MWkm. I.e. a short / low-capacity Overhead Line (OHL) would give as much weight to the findings as a large subsea High Voltage Direct Current (HVDC) bootstrap – however the conditions that drive the bootstrap investment will have a much greater relevance to overall system costs.

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(vi) Just because a background scenario best reflects the peak flow of a majority of circuits, it does not necessarily mean it is reflective of circuits in negative charging zones, or of the majority new circuits that need to be built.

A summary of some of Frontier's findings are as follows:

1. The current peak background only 'represents' 32% of circuits, and current year-round only 'represents' 33% of circuits. Over time, the peak background becomes less representative, and the year-round more representative.
2. Over time, the backgrounds will need to change – by 2035 they would require Biomass/Combined Cycle Gas Turbines (CCGTs)/Pump storage and Nuclear to be at 138% of output under the peak background, and –70% under the year-round background, which are non-sensical scenarios.
3. Over time (in 2035), the new proposed economic background (*Round 1*) best represents an increasing number of circuits (72% in Frontier's modelling v 32% for a security like background).
4. Over time, the appropriate economic background to use will not have a peak flow that occurs at ACS / system peak – in their analysis, in 2035 the 'year-round' like background, occurs at 61.5GW v a system peak of 72.1GW.
5. For 2025, a material number of circuits (15%) were represented by a background scenario with very low Demand flows – these were during high wind scenarios with exports via Interconnectors.

In the WACMI Proposer's view the conditions described under point 5 above suggest that in Frontier's modelling, circuits used under high wind conditions (i.e. the Scottish negative zones) have peak flows that are not correlated with peak Demand – but occur at lower Demand, however we do not have the detailed results from the LCP Delta modelling to confirm this explicitly. It is logical that high wind times drive the need for these circuits, irrespective of whether they occur at peak or not. It also makes sense to expect high wind at peak Demand has lower flows than high wind at

## Public

other times, as there is less local Demand to use the excess power in negative charging zones.

Frontier, having completed this modelling and presenting it in June 2023, did not interpret the results to mean that Demand over peak was the most appropriate driver of network investments over year-round circuits. Their position, as presented in January 2024, was that year-round Demand circuit expansion is driven by constraints, and year-round TNUoS circuits should be billed over either:

- (ii) Demand over all periods
- (ii) Demand over periods of constraint
- (ii) Demand over volume weighted periods of constraint

## The Transmission infrastructure investment process

Transmission infrastructure investments are not made based on the TNUoS model, or any similar transport model.

The following is a summary of the process based on information provided by NESO's Future Energy Scenarios (FES) Team:

- The FES Team creates four scenarios, one where net zero ambitions are not met, and three describing different decarbonisation paths to achieve net zero. For each of these pathways, generation and Demand are forecast for each zone behind an identified system constraint boundary. Each pathway is run using PLEXOS software to simulate day ahead unconstrained generation, Demand, and prices for each HH of each year, until 2050. The European market is also modelled on a HH basis to accurately enable simulation of Interconnector flows.
- The model is run again, but this time with the grid constraints in place, a redispatch process simulates bids and offers across each half hour (for example turning off wind behind a constraint and switching on thermal generation near areas of high Demand) and a balancing mechanism cost is derived on a granular level for each HH out to 2050.

## Public

- The output of this constrained model is the Electricity Ten Year Statement (ETYS), which is given to the Network Options Assessment Team (going forward the Strategic Energy Planning team).
- This is then shared with the Transmission operators, and NESO, along with the Transmission operators develop physical (wires and substations) and market led strategies that could alleviate these constraints to save system balancing mechanism costs.
- Once these options are received, PLEXOS energy market simulation software is again run with different reinforcements, and combinations of reinforcements to identify the best set of options for reducing constraints, and their potential benefits across each of FES scenarios out to 2050. The benefit in reduced constraint costs is compared with the cost to build and maintain these assets, with costs and savings discounted using the relevant Transmission operator's allowed Weighted Average Cost of Capital (WACC). This cost benefit analysis is repeated over multiple possible reinforcement strategies. The best combinations on a least worse regrets basis across the four FES scenarios are put forward as recommendations for Ofgem to approve.
- In Scotland, reinforcements to take power South are typically to alleviate constraints during periods of high wind, particularly when local Demand in Scotland is low. This is likely to be the case for the next 10-15 years until grid reinforcements catch up with the excess of wind generation expected. The situation is different in other areas, for example behind EC5 boundary (~Norfolk) where there are different types of generation, Interconnectors and generally more complex drivers of grid reinforcement.
- Increased Demand in areas of high wind generation behind Northern constraint boundaries will affect reinforcement decisions. However, it is predominantly Demand over high wind periods that would reduce constraint costs and North-South Transmission reinforcements requirements, not Demand at Triad (three highest peak Demand periods).

## Public

Therefore, given this feedback from FES Team, it is the WACMI Proposer's view that in GSP zones with negative locational signals, Demand over the whole year, is a much more accurate reflection of reduced infrastructure requirements than Demand at Triad or evening peak.

If Demand only across peak were a good reflection of the impact on grid investments, there would have been no need to introduce a floor in the first place – incentivising new or existing Users to increase Demand over Triad only would genuinely reduce costs and would be beneficial (but this is not the case).

## Magnitude of operational signal over charging period

Demand Zone		2026/7 Signal over charging Period £/MWh					2030/31 Signal over charging Period £/MWh				
		Baseline no floor		Proposer solution		WACMI	Baseline no floor		Proposer solution		WACMI
		HH	NHH	HH	NHH	Both	HH	NHH	HH	NHH	Both
1	Northern Scotland	25386	53.03	40.84	53.03	7.90	47106	95.87	75.78	95.87	14.11
2	Southern Scotland	18503	36.69	30.45	36.69	5.90	35218	66.34	57.97	66.34	10.61
3	Northern	9059	17.23	14.79	17.23	2.61	9370	17.04	15.29	17.04	2.56
4	North West	3618	7.28	6.01	7.28	1.07	4579	8.98	7.60	8.98	1.30
5	Yorkshire	3329	6.49	5.50	6.49	0.96	1886	3.54	3.12	3.54	0.53
6	N Wales & Mersey	1338	2.61	2.16	2.61	0.39	133	0.25	0.21	0.25	0.04
7	East Midlands	44	0.09	0.07	0.09	0.01	Zone no longer negative				

The data in the table above takes the 2026/27 and the 2030/31 published tariff from the 5-year forecast published in 2025. It shows the £/MWh strength of the signal under the baseline with the floor removed, the original Proposer's solution and the WACMI over their respective charging periods. The original Proposer's solution will rise to almost £100/MWh for North Scotland in the medium term. The Proposer of WACMI believes this will be an unhelpful operational signal to increase or shift Demand to the evening peak.

## Impact on different Demand profiles

Charging the predominantly (95%) year-round charges in negative TNUoS zones across the peak would reward the wrong type of Demand profile. Below are examples of how much of the negative signal different Demand profiles would see, comparing the baseline (floor removed), original proposal and WACMI.

## Public

### 1. Super Peaky Demand (1MW over three Triad periods)

Super Peaky Demand Zone		Annual Credit £ 2026/7				
HH / NHH		Baseline no floor		Proposer solution		WACM1
		HH	NHH	HH	NHH	Both
1	Northern Scotland	38,079	79.54	61.26	79.54	11.85
2	Southern Scotland	27,754	55.04	45.68	55.04	8.85
3	Northern	13,588	25.84	22.18	25.84	3.92
4	North West	5,427	10.93	9.01	10.93	1.61
5	Yorkshire	4,993	9.73	8.25	9.73	1.44
6	N Wales & Mersey	2,008	3.92	3.24	3.92	0.59
7	East Midlands	65	0.13	0.11	0.13	0.02

The above table shows the annual credit a 1MW Demand User would receive if they were only off taking for 1.5 hours over the 3 Triad periods. Either WACM1 or the original solution would be effective in removing the large incentive for very narrow Demand just at peaks. This is good, as in WACM1 Proposer's view, the actual Demand at ACS is not what drives Transmission infrastructure costs.

## Public

### 2. Very Peaky Demand (1MW each 4-7pm only)

Very Peaky Demand Zone		Annual Credit £ 2026/7				
HH / NHH		Status quo floor		Proposer solution		WACM1
		HH	NHH	HH	NHH	Both
1	Northern Scotland	38,079	58,065	44,718	58,065	8,647
2	Southern Scotland	27,754	40,179	33,347	40,179	6,463
3	Northern	13,588	18,862	16,190	18,862	2,862
4	North West	5,427	7,975	6,576	7,975	1,172
5	Yorkshire	4,993	7,104	6,022	7,104	1,051
6	N Wales & Mersey	2,008	2,861	2,363	2,861	428
7	East Midlands	65	97	81	97	15

The above table shows the annual credit that would be received by a Demand User who only ran over the 4-7pm evening peaks. This running profile would not be very effective at reducing constraints or North-South Transmission build out requirements, however under both the baseline (floor removed), or the original solution, a Demand (particularly NHH) would be very strongly rewarded for this profile. Under the WACM1 proposal, this type of User would be modestly rewarded, in line with the modest contribution to avoidance of constraints/infrastructure costs.

### 3. Offpeak Flex (1MW, all times except 4-7pm)

Off peak flex Demand Zone		Annual Credit £ 2026/7				
HH / NHH		Status quo floor		Proposer solution		WACM1
		HH	NHH	HH	NHH	Both
1	Northern Scotland	-	-	-	-	60,530
2	Southern Scotland	-	-	-	-	45,244
3	Northern	-	-	-	-	20,035
4	North West	-	-	-	-	8,203
5	Yorkshire	-	-	-	-	7,359
6	N Wales & Mersey	-	-	-	-	2,997
7	East Midlands	-	-	-	-	104



## Public

The above shows the strength of negative signal a IMW User would face if they ran in all hours except the evening 4-7pm peak. With an 88% capacity factor, this type of User is likely to run over most constrained hours, making a significant contribution to reducing constraint costs, however it is only under WACMI proposal, that such a User would see any of the Demand locational signal.

## WACMI Summary

The WACMI Proposer suggested this solution on the basis that it was:

- a) More practical: it avoided introducing an operational signal that would encourage increased Demand over peak Demand periods.
- b) Better aligned with the TNUoS model (it spread year-round circuits over year-round Demand)
- c) Better aligned with actual investment drivers, i.e. constraint avoidance, flows over high wind periods, full year-round generation/Demand modelling undertaken in the investment process.
- d) Supported by analysis completed by Frontier Economics and follows their conclusion regarding the appropriate charging base for year-round circuits.
- e) A good long term investment signal for all types of Demand that would be helpful in reducing network costs.
- f) Simple to implement and administer; and struck an appropriate balance between complexity and cost reflectivity.

Public

## Legal text

The legal text for this change can be found in **Annex 03**.

	CUSC Section 14
Original	Removes the zero-price floor, so negative p/kWh TNUoS Demand charges can be applied over 4–7pm all year to Final Demand (including Unmetered Supplies) in negative charging zones using a weighted average profile.
WACM1	Spreads negative charges across total all year Demand in those zones, using a single p/kWh rate for both HH and NHH customers.

The following considerations were taken into account when creating the legal text:

### Original solution

- The main sections affected are 14.15 (defining the effective tariff and final tariffs) and 14.16 (calculation details for pence per kWh tariffs). There are some minor changes to the description of the overall TNUoS process in Section 14.14.
- The original proposal maintains the process for calculating the final tariff from the effective tariff, with a correction to ensure the correct reference is used in 14.16 (should refer to final tariff, not effective tariff).
- There was discussion about the need to clarify the treatment of negative tariffs, ensuring that only Non-Final Demand is collared to zero, and that the wording should be improved for clarity. The Proposer provided suggestions for clearer language.
- The calculation for pence per kWh tariffs must be performed separately for NHH and HH Demand in the original proposal, as their profiles differ, and this distinction needs to be reflected in the legal drafting, by adding a clause 14.16.3 which is equivalent treatment for HH Demand as for NHH Demand in 14.16.2.

## Public

- The baseline legal text and calculation are believed to be inconsistent as they do not reflect the intent of the code or the way it is applied. The baseline legal text describes in words that the credit resulting from the application of the floor should be assigned to the value of the TDR, yet the formulae beneath those words spread this credit across locational tariffs in positive charging zones. There was agreement that the legal text should be updated to ensure the correct allocation of the credit to the TDR, and to clarify the application of the collar and the calculation steps.

## WACMI solution

- The WACMI legal text changes are the same as the original solution in sections 14.14.5, 14.15.137, 14.15.141 and 14.17.20.
- The WACMI legal text differs in 14.16.2 and the new clause 14.16.3.
- The additional clause 14.16.3 implements a calculation for both NHH and HH combined to derive negative p/kWh tariffs charged over the total Demand all year in negative charging zones.
- The legal text adjusted in 14.16.2 maintains the existing p/kWh calculation for positive zones and fixes a minor error in the baseline relating to an adjustment for mid-year tariffs. The WACMI legal text also differs from the original in 14.7.3, 14.17.13, 14.17.19, 14.17.21 and 14.27. These sections describe how p/kWh charges and £/kW charges are applied to Demand, and what forecast data Suppliers need to submit.

## Workgroup considerations

The Workgroup convened 14 times in order to discuss the identified issue 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

The Proposer presented their solution to the Workgroup, outlining that the modification has resulted from the TNUoS Taskforce. One Workgroup member queried the involvement of the Taskforce in CUSC modifications; the Proposer noted support from

## Public

Taskforce members for this proposal but advised that members had not unanimously agreed with all the suggested modifications.

### **Reasoning for excluding Non-Final Demand from the original proposal**

The Proposer advised that widening the charging periods to include more hours as a proxy for Triad consumption may lead to capturing Generator consumption, including storage. The Proposer considers this would be inappropriate as the derived p/kWh tariff is based on the assumption that the consumer adheres to a typical consumption profile. If a typical User consumption profile is applied to Non-Final Demand consumers, it would not be a good proxy for their Triad consumption. Therefore, a different profile and/or approach would be required. Non-Final Demand Users might each need a number of different proxy profiles resulting in a number of different p/kWh tariffs. This could be quite complex.

If this proposal was applied to Non-Final Demand, it would be most impactful on storage Users whose imports are most material compared to their export volumes and their TEC. The Proposer notes that the Storage TNUoS Subgroup, which initially met in June 2025, will be reviewing analysis on the impact of storage on Transmission network planning and are expected to develop proposals for TNUoS charges for storage, both import and export.

The Proposer also noted that the existing proposal, CMP405: TNUoS Locational Demand Signals for Storage, has already been raised to address the lack of locational incentives for storage due to the implementation of the Demand TNUoS floor. CMP405 seeks to separate out the Demand year-round locational signals from peak security locational signals and charge (reward) storage which imports during times other than Triads.

The Workgroup debated the issues of whether the scope of this code modification should be extended to include Non-Final Demand. Some Workgroup members believed that including Non-Final Demand would be a logical step as they felt there was insufficient reasoning to exclude these sites from the introduction of negative Demand TNUoS locational signals. The Proposer provided the arguments for restricting the scope to Final Demand, which are set out in the foregoing paragraphs of this report. Given this discussion, the Workgroup felt that this issue should become an

## Public

issue for consultation to the wider industry. This was reflected in question 11 in the Workgroup Consultation.

## Background Analysis

The Proposer highlighted that based on analysis presented to them on 26 June 2023 (available on the NESO Charging Futures website) by LCP Frontier, the TNUoS Taskforce had concluded that there was no case for change to replace or add additional TNUoS backgrounds, because the existing backgrounds based on ACS peak winter Demand periods were adequately representative of the network flows that drive network expansion for most circuits.

There initially appeared to be a case for adjusting or updating the assumed generation scaling factors for Interconnectors and Pumped Storage in those existing backgrounds because they did not appear to be representative of generation levels that caused maximum flows.

However, Frontier presented detailed sensitivity analysis to the Taskforce that showed updating the backgrounds would have limited impact on tariffs. They explained that this was because the objective of the background is only to set the “starting” conditions for modelling the impact of an incremental 1MW of generation.

Amending the scaling factors only has an impact on tariffs if the background flows reverse or if a circuit’s maximum flow changes from being allocated from one background to the other (e.g. if peak flows become higher than year-round flows in which case the incremental Transmission cost moves from the Year-Round Tariff to the Peak Tariff and vice versa).

Frontier illustrated that if scaling factors were updated, tariffs would remain similar. Furthermore, the current year-round scaling factors are based on the level of generation accommodated through an optimal level of Transmission build and constraints.

However, the LCP Frontier analysis examines maximum (not optimal) network flows without constraints. It would be expected that generation scaling factors would be different, and if anything, probably higher in the LCP Frontier analysis compared to the existing year-round background. To be confident of an improvement to scaling factors, it would likely be necessary to undertake more in-depth analysis by NESO of the optimal level of Transmission build.

## Public

Frontier Economics had used a network model to analyse network flows for the FES System Transformation scenario for 2025. They derived sets of generation scaling factors. These reported the percentage of circuits for which those scaling factors recreated network flows that were within 90% of the peak flow in their model, i.e. the percentage of the network for which that generation configuration drives expansion. It is worth noting that the updated “Round 1” background scaling factors that LCP Frontier derived are very similar to the current year-round background which includes the locational distribution of consumer Demand at over 50GW (similar to winter ACS peak).

The Round 1 background is the best configuration that represents the network conditions that drive expansion for the most circuits, and this background would drive expansion for 59% of circuits.

The updated “Round 2” background that LCP Frontier derived is very similar to the current peak background which also includes the locational distribution of consumer Demand at over 50GW (also similar to winter ACS peak). The Round 2 background represents the network conditions that drive expansion for an additional 8% of circuits i.e. Round 1 and Round 2 together represent the conditions that drive expansion for 67% of the network.

Frontier derived a third, “Round 3”, background which further represents the network conditions that drive expansion for an additional 9% of circuits. It is only in this third background representing an additional 9% of circuits that Demand is low, at 26.5GW. This analysis calls into question the assertion that peak network flows mostly occur at low Demand. There could well be significant overlap between Round 1 and Round 3 backgrounds in similarly driving network expansion, but this requires further analysis.

The retention of the existing backgrounds with winter ACS peak conditions as still being largely valid in representing the conditions that drive most network expansion is a key driver for the Proposer considering that Demand TNUoS charges should continue to be based on Demand at Triad as the equivalent of Generator TEC.

## Public

Table 4 – LCP Frontier's analysis of the degree to which backgrounds represent maximum network flows

Technology	Current backgrounds		Most representative backgrounds (2025, NGENO FES ST scenario)		
	Peak	Year-round	Round 1	Round 2	Round 3
Biomass	88%	27%	68%	68%	3%
OCGT	88%	0%	0%	77%	0%
CCGT	88%	27%	21%	95%	0%
Hydro	88%	27%	64%	64%	0%
Interconnectors	0%	100%	48%	59%	-80%
Nuclear	88%	85%	100%	100%	100%
Wind Offshore	0%	70%	87%	4%	87%
Wind Onshore	0%	70%	81%	4%	77%
Pump Storage	88%	50%	0%	58%	-61%
Demand (MW)	52,417	52,417	50,547	50,770	26,508
Individual % represented	32%	33%	59%	27%	15%
Cumulative % represented	32%	43%	59%	67%	76%

Current Peak and YR scenarios do not provide a very good representation for over half of the network.

Similar to YR

Similar to peak

## Initial discussion on converting the £/kW tariff to p/kWh for wider charging periods

The Proposer presented the current approach to converting the tariff for NHH customers in positive zones from £/kW to p/kWh. The Proposer explained that the p/kWh tariff is set so that it collects the same amount of revenue from NHH customers in each GSP group as it would if the charge was levied based on consumption at Triad.

This calculation is laid out in CUSC Section 14.16.2 as follows:

$$\frac{p}{kWh} \text{ Tariff} =$$

$$\frac{\text{NHH GSP Group Demand at Triad} \times \frac{\text{£}}{\text{kW}} \text{ Tariff}}{\text{Measured NHH GSP Group Demand 4-7pm}} \times \frac{100p}{\text{£}}$$



## Public

So, for example, in Zone 13, GSP Group H, the Southern HH Demand Tariff is £7.65/kW for 2025/26. Consideration should be given to the forecast average MW offtake as per the table below to calculate the p/kWh tariff needed to deliver the same revenue that would be collected if Demand was levied on Triad consumption:

Period	Hours of measurement period	Forecast Average Demand Group H	Forecast Actual Energy Consumption
Triad	<b>1.5hrs</b>	3020MW	-
4-7pm All Year	3 x 365 = <b>1095hrs</b>	2140MW	2140MW x 1095hrs = <b>2,343,300MWh</b>
All Year	24 x 365 = <b>8760hrs</b>	1820MW	1820MW x 8760hrs = <b>15,943,200MWh</b>

If Demand is measured based on consumption 4-7pm, the calculation is as follows:

$$\frac{p}{kWh} \text{ Tariff} = \frac{3020MW \times \frac{£7.65}{kW} \times \frac{1000kW}{MW}}{2140MW \times 1095hrs \times \frac{100p}{£}} = 0.099p/kWh = \frac{3020MW}{2140MW} \times \frac{£7.65}{kW} \times \frac{100p}{£}$$

Output from TNUoS Transport and Tariff Model

The important ratio is demand at triad vs average demand during the measured consumption period when converting tariffs from £/kW to p/kWh

Fixed data components (in black font)

The Proposer highlighted the challenge of converting the current £/kW tariff to p/kWh for HH customers (required due to levying charges over a wider period of consumption). One Workgroup member suggested using a function of distribution charges. They discussed aligning the model more with the generation model instead of converting it to p/kWh. They proposed using connection capacity to calculate ALFs instead of TEC. Additionally, they queried if TNUoS could be modified to allow Distribution Network Operators (DNOs) to pay for Demand TNUoS and then feed this cost back to Suppliers through the Distribution Use of System (DUoS) models.

One Workgroup member queried if negative charging was less of an issue for NHH customers. The Workgroup discussed the split between peak and year-round charges,

## Public

noting some circuits will be at max flow during peak, and some at year-round (in the high wind scenario). The Proposer noted that Peak and Year-Round Tariffs represent different circuits across the network.

The Workgroup discussed whether Triads should be used for the maximum capacity requirement, with one Workgroup member noting that for generation, the calculation of negative tariffs uses a site's maximum local peaks, which is different to Triad. They queried whether it was better to use this measure for positive HH charging rather than Triad to make the solution more cost reflective. The Proposer highlighted that the model should attempt to represent peak Demand for the whole system and everyone's contribution to it so advised that they thought Triad was the right measure to use, noting that Demand Triads should be the maximum system capacity at any one time.

## Discussion on electrolyzers

The Proposer presented that electrolyzers are an important future source of Demand that is expected to be able to respond to long term locational cost signals to some extent and noted that it is not clear at this stage whether electrolyser Demand will be included in the definition of Final Demand. The Proposer felt that if excluded, the scope of changes under this modification should be revisited to include electrolyzers. The Workgroup discussed electrolyzers, with one Workgroup member noting that clarity was required as to whether electrolyser Demand will be included in the definition of Final Demand. The NESO representative advised that CUSC definitions define Final Demand in Section 11 thus:

**"Final Demand"** Means electricity which is consumed other than for the purposes of generation or export onto the electricity network".

**"Final Demand Site"** Shall mean;

1. For Users with a Bilateral Connection Agreement (BCA), a Single Site which has associated Final Demand, except Single Sites which are for; a. Users who own or operate a Distribution System, or b. Interconnector Users, or c. Users of a Non-Final Demand Site with a valid Declaration.
2. For Users with a Bilateral Embedded Generation Agreement (BEGA) or Bilateral Exemptible Large License-exempt Generator Agreement (BELLA), as defined as 'Final Demand Site' in the Distribution Connection and Use of System Agreement (DCUSA) except Non-Final Demand Site with a valid Declaration.

## Public

3. For all other parties, as defined as 'Final Demand Site' in the DCUSA.

The NESO representative noted, concluding, that electrolyzers in general will not be storage, therefore NESO would treat them as Final Demand and they would be subject to locational Demand signals. If an electrolyser is a part of a pure seasonal electricity storage facility, it would declare itself as such and would, presuming such declaration had been accepted as valid, then comprise Non-Final Demand.

The Workgroup noted that the issue of whether Electrolysers should be liable for levies was an Authority/DESNZ policy matter, as levies are defined in legislation.

It was noted that electrolyzers are by default treated as any other Final Demand but are eligible (subject to the same qualifying criteria as other Final Demand) to participate in the Energy Intensive Industries (EII) scheme which offers 100% discounts on Final Consumption Levies/ Capacity Market payments, and the Network Charge Compensation (NCC) scheme which offers 60% discounts (increasing to 90% discount from 1/4/2026<sup>2</sup>) on grid charges including Balancing Services Use of System (BSUoS) and TNUoS to qualifying sites of sufficient size<sup>3</sup>. The government have also committed to exempting electrolytic hydrogen production from Climate Change Levy (CCL) payments. The Proposers of the original and WACMI met with Department of Business and Trade, which confirmed in principle they would be supportive of industry being able to separate out TNUoS locational credits from their NCC Scheme discount and therefore retain 100% of the locational benefit. However, there was no discussion as to how this could be implemented in practice; to do this, an electrolyser customer would need to receive separated locational and residual TNUoS invoice line items from its Supplier.

## Analysis on impact of the solution on customers

### Deriving Proposed Tariffs

The Proposer discussed with the Workgroup the current approach in deriving pence per kWh (p/kWh) tariffs as defined in the baseline legal text in CUSC Section 14.16.2. The

<sup>2</sup> <https://www.gov.uk/government/consultations/network-charging-compensation-scheme-uplift-for-energy-intensive-industries/outcome/proposed-uplift-to-the-network-charging-compensation-scheme-for-energy-intensive-industries-eiis-government-consultation-response>

<sup>3</sup> The Industrial Strategy in June 2025 has confirmed that the support available through NCC scheme will rise from 60% to 90%. [Clean Energy Industries Sector Plan – GOV.UK](#)

## Public

Proposer explained that a similar approach was proposed to be used to derive p/kWh tariffs in negative charging zones.

The Proposer explained that the conversion to a p/kWh approach is done for positive NHH tariffs zone by zone. NESO provided data to show the ratios of forecast Triad Demand to average Demand 4-7pm and average Demand all year. These ratios vary slightly by zone.

The Proposer noted that in the initial proposal, peak and year-round charging periods would have been different in negative zones and so there would have been a need to calculate and present these tariffs separately.

However, in the original proposal, the peak and year-round charging periods are the same, so these tariffs can be added together and a total tariff presented.

**Table 5 – Current Baseline**

	Half Hourly Customers		Non-Half Hourly Customers	
	Peak	Year Round	Peak	Year Round
Negative Charges	Zero	← same → Zero	Zero	← same → Zero
Positive Charges	Triad	← same → Triad	4-7pm all year	← same → 4-7pm all year

**Table 6 – Initial Original Proposal**

	Half Hourly Customers		Non-Half Hourly Customers	
	Peak	Year Round	Peak	Year Round
Negative Charges	4-7pm all year	← different → All year	4-7pm all year	← different → All year
Positive Charges	Triad	← same → Triad	4-7pm all year	← same → 4-7pm all year

Different charging period for different components



**Table 7 – Updated Original Proposal**

	Half Hourly Customers		Non-Half Hourly Customers	
	Peak	Year Round	Peak	Year Round
Negative Charges	4-7pm all year	← same → 4-7pm all year	4-7pm all year	← same → 4-7pm all year
Positive Charges	Triad	← same → Triad	4-7pm all year	← same → 4-7pm all year

Same charging period for different components



## Public

**Table 8 – Demand at Triad (MW) vs Average Demand Over Charging Period (MW)**

Zone	Zone Name	Total Triad Demand (GW)	HH Triad Demand (MW)	NHH Triad Demand (MW)	HH		NHH		HH		NHH	
					4-7pm	all periods	4-7pm	all periods	Triad (MW) vs	Triad (MW) vs all periods	Triad (MW) vs	Triad (MW) vs all periods
					Demand (TWh)	Demand (TWh)	Demand (TWh)	Demand (TWh)	4-7pm Demand (MW)	Demand (MW)	4-7pm Demand (MW)	Demand (MW)
1	Northern Scotland	1.38	389.02	993.89	0.36	2.74	0.71	3.91	1.17	1.24	1.53	2.23
2	Southern Scotland	3.17	1,071.85	2,098.11	0.98	6.88	1.58	8.01	1.20	1.36	1.45	2.30
3	Northern	2.32	897.40	1,425.73	0.82	6.24	1.12	5.85	1.19	1.26	1.39	2.13
4	North West	3.71	1,273.98	2,438.04	1.15	9.27	1.81	9.54	1.22	1.20	1.47	2.24
5	Yorkshire	3.56	1,415.60	2,147.28	1.28	9.87	1.66	8.66	1.21	1.26	1.42	2.17
6	N Wales & Mersey	2.42	888.10	1,531.54	0.82	6.26	1.17	6.15	1.18	1.24	1.43	2.18
7	East Midlands	4.37	1,552.15	2,818.41	1.37	9.72	2.07	11.34	1.24	1.40	1.49	2.18
8	Midlands	3.90	1,320.94	2,578.10	1.17	9.76	1.91	10.46	1.23	1.19	1.48	2.16
9	Eastern	5.94	1,789.78	4,153.78	1.66	11.44	2.88	15.85	1.18	1.37	1.58	2.30
10	South Wales	1.69	688.21	1,001.41	0.66	5.04	0.81	4.60	1.14	1.20	1.35	1.91
11	South East	3.64	969.63	2,666.15	0.90	6.79	1.84	10.25	1.19	1.25	1.58	2.28
12	London	3.85	2,047.49	1,798.58	1.97	14.93	1.66	9.63	1.14	1.20	1.18	1.64
13	Southern	5.13	1,788.19	3,343.85	1.70	12.25	2.45	14.09	1.15	1.28	1.49	2.08
14	South Western	2.45	597.22	1,855.63	0.55	4.18	1.27	7.31	1.19	1.25	1.59	2.22

**Table 9 – Proposal Charging Periods and conversion ratios**

	Half Hourly Customers		Non-Half Hourly Customers	
	Peak	Year Round	Peak	Year Round
	Negative	4-7pm all year	All year	4-7pm all year
Positive	Triad	Triad	4-7pm all year	4-7pm all year

	Half Hourly Customers		Non-Half Hourly Customers	
	Peak	Year Round	Peak	Year Round
	Negative	4-7pm all year	4-7pm all year	4-7pm all year
Positive	Triad	Triad	4-7pm all year	4-7pm all year

Demand Zone		2026/27 TNUoS Transport Model Output			Initial Original Proposal								Updated Original Proposal			
		Peak (£/kW)	Year Round (£/kW)	Total (£/kW)	Charging Period				Ratio for deriving p/kWh charge				Charging Period		Ratio for deriving p/kWh charge	
					HH	Year Round	NHH	Year Round	HH	Year Round	NHH	Year Round	HH	NHH	HH	NHH
1	Northern Scotland	-1.84	-36.24	-38.08	4-7pm	All Year	4-7pm	All Year	1.00	1.00	1.00	1.00	4-7pm	4-7pm	1.17	1.53
2	Southern Scotland	-2.41	-25.35	-27.75	4-7pm	All Year	4-7pm	All Year	1.00	1.00	1.00	1.00	4-7pm	4-7pm	1.20	1.45
3	Northern	-3.72	-9.87	-13.59	4-7pm	All Year	4-7pm	All Year	1.00	1.00	1.00	1.00	4-7pm	4-7pm	1.19	1.39
4	North West	-1.81	-3.61	-5.43	Triad	All Year	4-7pm	All Year	Triad	1.00	1.00	1.00	4-7pm	4-7pm	1.22	1.47
5	Yorkshire	-2.81	-2.19	-4.99	4-7pm	All Year	4-7pm	All Year	1.00	1.00	1.00	1.00	4-7pm	4-7pm	1.21	1.42
6	N Wales & Mersey	-2.86	0.85	-2.01	4-7pm	All Year	4-7pm	All Year	1.00	1.00	1.00	1.00	4-7pm	4-7pm	1.18	1.43
7	East Midlands	-2.23	2.16	-0.07	4-7pm	Triad	4-7pm	4-7pm	1.00	Triad	1.49	1.49	4-7pm	4-7pm	1.24	1.49
8	Midlands	-1.54	5.31	3.77	4-7pm	Triad	4-7pm	4-7pm	1.00	Triad	1.48	1.48	4-7pm	4-7pm	Triad	1.48
9	Eastern	1.49	-0.85	0.65	Triad	Triad	4-7pm	4-7pm	Triad	Triad	1.58	1.58	Triad	4-7pm	Triad	1.58
10	South Wales	-4.02	10.07	6.05	4-7pm	Triad	4-7pm	4-7pm	1.00	Triad	1.35	1.35	Triad	4-7pm	Triad	1.35
11	South East	4.23	1.21	5.44	Triad	Triad	4-7pm	4-7pm	Triad	Triad	1.58	1.58	Triad	4-7pm	Triad	1.58
12	London	4.81	2.25	7.06	Triad	Triad	4-7pm	4-7pm	Triad	Triad	1.18	1.18	Triad	4-7pm	Triad	1.18
13	Southern	2.62	5.64	8.26	Triad	Triad	4-7pm	4-7pm	Triad	Triad	1.49	1.49	Triad	4-7pm	Triad	1.49
14	South Western	2.08	11.84	13.92	Triad	Triad	4-7pm	4-7pm	Triad	Triad	1.59	1.59	Triad	4-7pm	Triad	1.59

The Proposer initially suggested considering different charging periods, specifically proposing to charge both peak and year-round from 4 to 7pm to simplify the process. The Workgroup raised concerns about the operational impact of spreading charges

## Public

over a longer period, particularly in Scotland, where it might affect Demand and power prices. The Workgroup discussed the importance of moving away from the Triad to provide a better operational signal and reduce costs to consumers.

### **Original proposal's baseload approach**

The Proposer went on to discuss a baseload profile for all noting:

- Currently, the p/kWh positive tariff for NHH consumers is multiplied by ~1.4 to account for an assumed lower rate of Demand during the 4-7pm-All-Year measurement period compared with Triad Demand, as well as dividing this by the number of hours over which consumption is measured to arrive at a p/kWh as opposed to a £/kW tariff.
- Baseload consumers would be over incentivised to locate in negative zones if their rate of Demand over the measurement period (compared to their Triad Demand) is higher than average, so the initial original proposal was for a baseload consumption profile to be assumed when deriving tariffs, i.e. instead of multiplying the p/kWh tariff to account for a lower level of average rate of consumption over the charging period, a multiplier of only 1 is used.

The Workgroup considered resulting tariffs using the total zonal average forecast consumption profile vs assuming a baseload consumption profile for negative tariffs as below.

## Public

**Table 10 – Initial Original Proposal Illustrative Tariffs for 2026/27 Charging Year**

Current Baseline Methodology (all Users)		CMP440 Original as initially proposed using assumed baseload profile						CMP440 Original initial proposal if an average consumption profile had been used								
(no floor for illustration)		Non-Final Demand	Final Demand						Non-Final Demand	Final Demand						
HH	NHH		HH			NHH				HH	HH			NHH		
(Triad)	(4-7pm)		Triad	4-7	all periods	4-7	all periods	(Triad)		Triad	4-7	all periods	4-7	all periods		
£/kW	p/kWh	£/kW	£/kW	p/kWh	p/kWh	p/kWh	p/kWh	£/kW	£/kW	p/kWh	p/kWh	p/kWh	p/kWh			
-38.08	-5.34	-	-	-0.17	-0.41	-0.17	-0.41	-	-	-0.20	-0.51	-0.26	-0.92			
-27.75	-3.68	-	-	-0.22	-0.29	-0.22	-0.29	-	-	-0.26	-0.39	-0.32	-0.66			
-13.59	-1.73	-	-	-0.34	-0.11	-0.34	-0.11	-	-	-0.41	-0.14	-0.47	-0.24			
-5.43	-0.73	-	-	-0.17	-0.04	-0.17	-0.04	-	-	-0.20	-0.05	-0.24	-0.09			
-4.99	-0.65	-	-	-0.26	-0.02	-0.26	-0.02	-	-	-0.31	-0.03	-0.36	-0.05			
-2.01	-0.26	-	0.85	-0.26	-	-0.15	-	-	0.85	-0.31	-	-0.26	-			
-0.07	-0.01	-	2.16	-0.20	-	0.09	-	-	2.16	-0.25	-	-0.01	-			
3.77	0.51	3.77	5.31	-0.14	-	0.58	-	3.77	5.31	-0.17	-	0.51	-			
0.65	0.09	0.65	1.49	-	-0.01	0.22	-0.01	0.65	1.49	-	-0.01	0.22	-0.02			
6.05	0.74	6.05	10.07	-0.37	-	0.87	-	6.05	10.07	-0.42	-	0.74	-			
5.44	0.79	5.44	5.44	-	-	0.79	-	5.44	5.44	-	-	0.79	-			
7.06	0.76	7.06	7.06	-	-	0.76	-	7.06	7.06	-	-	0.76	-			
8.26	1.13	8.26	8.26	-	-	1.13	-	8.26	8.26	-	-	1.13	-			
13.92	2.03	13.92	13.92	-	-	2.03	-	13.92	13.92	-	-	2.03	-			

The Workgroup concluded that there was no strong support for retaining the baseload approach and suggested changing the original proposal to use the forecast average profile, which is simpler and more straightforward.

### Impact of the proposed changes on domestic and commercial bills

The Proposer presented to the Workgroup the impacts of the proposed change on domestic and commercial bills, providing specific examples showing how the removal of the floor and the new charging periods would affect the annual bills of customers in different zones.



## Public

**Table 11 – Initial Original Proposal Impact on Domestic Bill for 2026/27 Charging Year**

Zone	Zone Name	Current methodology			Current methodology but no floor			CMP440 Original as initially proposed using assumed baseload profile					CMP440 Original as initially proposed using average profile				
		Locational Charge £	TDR £	Total £	Locational Charge £	TDR £	Total £	Locational Charge £	TDR £	Total £	Total Change vs Current	Total Change vs Current no floor	Locational Charge £	TDR £	Total £	Total Change vs Current	Total Change vs Current no floor
1	Northern Scotland	-	49.29	49.29	-26.94	52.06	25.11	-13.13	50.81	37.68	-24%	50%	-28.68	52.06	23.37	-53%	-7%
2	Southern Scotland	-	49.29	49.29	-18.57	52.06	33.49	-9.70	50.81	41.11	-17%	23%	-21.33	52.06	30.72	-38%	-8%
3	Northern	-	49.29	49.29	-8.72	52.06	43.34	-5.06	50.81	45.75	-7%	6%	-9.53	52.06	42.53	-14%	-2%
4	North West	-	49.29	49.29	-3.69	52.06	48.37	-2.06	50.81	48.75	-1%	1%	-3.98	52.06	48.08	-2%	-1%
5	Yorkshire	-	49.29	49.29	-3.27	52.06	48.79	-2.04	50.81	48.78	-1%	-0%	-3.45	52.06	48.61	-1%	-0%
6	N Wales & Mersey	-	49.29	49.29	-1.32	52.06	50.73	-0.76	50.81	50.05	2%	-1%	-1.32	52.06	50.73	3%	0%
7	East Midlands	-	49.29	49.29	-0.04	52.06	52.01	0.46	50.81	51.27	4%	-1%	-0.04	52.06	52.01	6%	0%
8	Midlands	2.58	49.29	51.87	2.58	52.06	54.63	2.92	50.81	53.73	4%	-2%	2.58	52.06	54.63	5%	0%
9	Eastern	0.47	49.29	49.76	0.47	52.06	52.53	0.80	50.81	51.61	4%	-2%	0.43	52.06	52.49	5%	-0%
10	South Wales	3.76	49.29	53.05	3.76	52.06	55.81	4.40	50.81	55.21	4%	-1%	3.76	52.06	55.81	5%	0%
11	South East	3.97	49.29	53.26	3.97	52.06	56.03	3.97	50.81	54.78	3%	-2%	3.97	52.06	56.03	5%	0%
12	London	3.85	49.29	53.14	3.85	52.06	55.91	3.85	50.81	54.66	3%	-2%	3.85	52.06	55.91	5%	0%
13	Southern	5.69	49.29	54.98	5.69	52.06	57.74	5.69	50.81	56.50	3%	-2%	5.69	52.06	57.74	5%	0%
14	South Western	10.23	49.29	59.52	10.23	52.06	62.29	10.23	50.81	61.04	3%	-2%	10.23	52.06	62.29	5%	0%

**Table 12 – Initial Original Proposal Impact on 30MW EHV Baseload commercial User bill for 2026/27 Charging Year**

Zone	Zone Name	Current methodology			Current methodology but no floor			CMP440 Original as initially proposed using assumed baseload profile					CMP440 Original as initially proposed using average profile				
		Locational Charge £m	TDR £m	Total £m	Locational Charge £m	TDR £m	Total £m	Locational Charge £m	TDR £m	Total £m	Total Change vs Current	Total Change vs Current no floor	Locational Charge £m	TDR £m	Total £m	Total Change vs Current	Total Change vs Current no floor
1	Northern Scotland	-	1.417	1.417	-1.142	1.497	0.354	-1.142	1.461	0.319	-78%	-10%	-1.418	1.497	0.079	-94%	-78%
2	Southern Scotland	-	1.417	1.417	-0.833	1.497	0.664	-0.833	1.461	0.628	-56%	-5%	-1.124	1.497	0.373	-74%	-44%
3	Northern	-	1.417	1.417	-0.408	1.497	1.089	-0.408	1.461	1.053	-26%	-3%	-0.506	1.497	0.990	-30%	-9%
4	North West	-	1.417	1.417	-0.163	1.497	1.334	-0.163	1.461	1.298	-8%	-3%	-0.197	1.497	1.300	-8%	-3%
5	Yorkshire	-	1.417	1.417	-0.150	1.497	1.347	-0.150	1.461	1.311	-7%	-3%	-0.184	1.497	1.312	-7%	-3%
6	N Wales & Mersey	-	1.417	1.417	-0.060	1.497	1.437	-0.060	1.461	1.401	-1%	-2%	-0.076	1.497	1.421	0%	-1%
7	East Midlands	-	1.417	1.417	-0.002	1.497	1.495	-0.002	1.461	1.459	3%	-2%	-0.018	1.497	1.479	4%	-1%
8	Midlands	0.113	1.417	1.530	0.113	1.497	1.610	0.113	1.461	1.574	3%	-2%	0.102	1.497	1.599	4%	-1%
9	Eastern	0.019	1.417	1.437	0.019	1.497	1.516	0.019	1.461	1.480	3%	-2%	0.010	1.497	1.507	5%	-1%
10	South Wales	0.181	1.417	1.599	0.181	1.497	1.678	0.181	1.461	1.642	3%	-2%	0.164	1.497	1.661	4%	-1%
11	South East	0.163	1.417	1.580	0.163	1.497	1.660	0.163	1.461	1.624	3%	-2%	0.163	1.497	1.660	5%	0%
12	London	0.212	1.417	1.629	0.212	1.497	1.708	0.212	1.461	1.673	3%	-2%	0.212	1.497	1.708	5%	0%
13	Southern	0.248	1.417	1.665	0.248	1.497	1.745	0.248	1.461	1.709	3%	-2%	0.248	1.497	1.745	5%	0%
14	South Western	0.418	1.417	1.835	0.418	1.497	1.914	0.418	1.461	1.878	2%	-2%	0.418	1.497	1.914	4%	0%

The Workgroup discussed the complexities of the proposed changes, including the potential for multiple permutations of tariffs. They considered ways to simplify the methodology while maintaining cost reflectivity and fairness for different customer types.

## Public

### Design components and option choices

The Workgroup discussed the different possible permutations of alternative solutions listed as follows:

#### Charging Period

- Peak 4-7pm all year, year-round all year
- Peak and year-round 4-7pm all year
- Peak and year-round all year

#### How much revenue to allocate to negative charging zones

- Full benefit, accounting for the expected lower rate of average offtake during the charging period compared with Triad
- Lower amount, not accounting for the expected lower rate of average offtake during the charging period compared with Triad

#### When to Use Negative Charging Approach

- If either year-round or peak component is negative, apply to negative tariff only
- If sum of year-round and peak is negative, apply to negative total tariff
- Apply to negative and positive tariffs (i.e. adopt new consistent approach)

#### Customer categories for calculating p/kWh

- NHH and HH tariffs are the same
- NHH and HH tariffs are different
- NHH and HH tariffs are different with further sub-division based on measurement class"

### Updated Solution

Following further development of the solution, the Proposer made the following amendments:

- Negative tariffs in p/kWh are arrived at by scaling the corresponding £/kW Demand Locational Tariff by the forecast total GSP metered consumption over

## Public

the charging period divided by total GSP peak consumption (i.e. using the weighted average profile, instead of assuming a baseload profile for all); and

- Both Peak and Year-Round Tariffs would be levied 4-7pm all year for both HH and NHH customers in negative charging zones. This makes the tariff tables much less complex

**Table 13 – Original Updated Proposal Illustrative Tariffs for 2026/27 Charging Year**

Zone	Zone Name	Current Tariff Methodology		Current Baseline Methodology (all Users)		CMP440 Original Updated Proposal			
		Demand Tariffs		(no floor for illustration)		Non-Final Demand	Final Demand		
		HH	NHH	HH	NHH	HH	HH		NHH
		Triad £/kW	4-7 p/kWh	(Triad) £/kW	(4-7pm) p/kWh	(Triad) £/kW	Triad £/kW	4-7 p/kWh	4-7 p/kWh
1	Northern Scotland	-	-	-38.08	-5.34	-	-	-4.08	-5.34
2	Southern Scotland	-	-	-27.75	-3.68	-	-	-3.05	-3.68
3	Northern	-	-	-13.59	-1.73	-	-	-1.48	-1.73
4	North West	-	-	-5.43	-0.73	-	-	-0.60	-0.73
5	Yorkshire	-	-	-4.99	-0.65	-	-	-0.55	-0.65
6	N Wales & Mersey	-	-	-2.01	-0.26	-	-	-0.22	-0.26
7	East Midlands	-	-	-0.07	-0.01	-	-	-0.01	-0.01
8	Midlands	3.77	0.51	3.77	0.51	3.77	3.77	-	0.51
9	Eastern	0.65	0.09	0.65	0.09	0.65	0.65	-	0.09
10	South Wales	6.05	0.74	6.05	0.74	6.05	6.05	-	0.74
11	South East	5.44	0.79	5.44	0.79	5.44	5.44	-	0.79
12	London	7.06	0.76	7.06	0.76	7.06	7.06	-	0.76
13	Southern	8.26	1.13	8.26	1.13	8.26	8.26	-	1.13
14	South Western	13.92	2.03	13.92	2.03	13.92	13.92	-	2.03

# Public

**Table 14 – Original Updated Proposal Impact on Domestic Bill for 2026/27 Charging Year**

Zone	Zone Name	Current methodology			Current methodology but no floor			CMP440 Original updated				
		Locational Charge £	TDR £	Total £	Locational Charge £	TDR £	Total £	Locational Charge £	TDR £	Total £	Total Change vs Current %	Total Change vs Current no floor %
1	Northern Scotland	-	49.29	49.29	-26.94	52.06	25.11	-26.94	52.06	25.11	-49%	0%
2	Southern Scotland	-	49.29	49.29	-18.57	52.06	33.49	-18.57	52.06	33.49	-32%	0%
3	Northern	-	49.29	49.29	-8.72	52.06	43.34	-8.72	52.06	43.34	-12%	0%
4	North West	-	49.29	49.29	-3.69	52.06	48.37	-3.69	52.06	48.37	-2%	0%
5	Yorkshire	-	49.29	49.29	-3.27	52.06	48.79	-3.27	52.06	48.79	-1%	0%
6	N Wales & Mersey	-	49.29	49.29	-1.32	52.06	50.73	-1.32	52.06	50.73	3%	0%
7	East Midlands	-	49.29	49.29	-0.04	52.06	52.01	-0.04	52.06	52.01	6%	0%
8	Midlands	2.58	49.29	51.87	2.58	52.06	54.63	2.58	52.06	54.63	5%	0%
9	Eastern	0.47	49.29	49.76	0.47	52.06	52.53	0.47	52.06	52.53	6%	0%
10	South Wales	3.76	49.29	53.05	3.76	52.06	55.81	3.76	52.06	55.81	5%	0%
11	South East	3.97	49.29	53.26	3.97	52.06	56.03	3.97	52.06	56.03	5%	0%
12	London	3.85	49.29	53.14	3.85	52.06	55.91	3.85	52.06	55.91	5%	0%
13	Southern	5.69	49.29	54.98	5.69	52.06	57.74	5.69	52.06	57.74	5%	0%
14	South Western	10.23	49.29	59.52	10.23	52.06	62.29	10.23	52.06	62.29	5%	0%

## Public

**Table 15 – Original Updated Proposal Impact on 30MW EHV Baseload commercial User bill for 2026/27 Charging Year**

Zone	Zone Name	Current methodology			Current methodology but no floor			CMP440 Original updated				
		Locational Charge £m	TDR £m	Total £m	Locational Charge £m	TDR £m	Total £m	Locational Charge £m	TDR £m	Total £m	Total Change vs Current	Total Change vs Current no floor
1	Northern Scotland	-	1.417	1.417	-1.142	1.497	0.354	-1.340	1.497	0.157	-89%	-56%
2	Southern Scotland	-	1.417	1.417	-0.833	1.497	0.664	-1.001	1.497	0.496	-65%	-25%
3	Northern	-	1.417	1.417	-0.408	1.497	1.089	-0.486	1.497	1.010	-29%	-7%
4	North West	-	1.417	1.417	-0.163	1.497	1.334	-0.198	1.497	1.298	-8%	-3%
5	Yorkshire	-	1.417	1.417	-0.150	1.497	1.347	-0.181	1.497	1.315	-7%	-2%
6	N Wales & Mersey	-	1.417	1.417	-0.060	1.497	1.437	-0.071	1.497	1.426	1%	-1%
7	East Midlands	-	1.417	1.417	-0.002	1.497	1.495	-0.002	1.497	1.494	5%	-0%
8	Midlands	0.113	1.417	1.530	0.113	1.497	1.610	0.113	1.497	1.610	5%	0%
9	Eastern	0.019	1.417	1.437	0.019	1.497	1.516	0.019	1.497	1.516	6%	0%
10	South Wales	0.181	1.417	1.599	0.181	1.497	1.678	0.181	1.497	1.678	5%	0%
11	South East	0.163	1.417	1.580	0.163	1.497	1.660	0.163	1.497	1.660	5%	0%
12	London	0.212	1.417	1.629	0.212	1.497	1.708	0.212	1.497	1.708	5%	0%
13	Southern	0.248	1.417	1.665	0.248	1.497	1.745	0.248	1.497	1.745	5%	0%
14	South Western	0.418	1.417	1.835	0.418	1.497	1.914	0.418	1.497	1.914	4%	0%

## Workgroup Consultation Summary

The Workgroup Consultation was held between 10 and 31 July 2025 and received four non-confidential responses were received, which were all from Workgroup members. These responses, and a summary of them, can be found **Annexes 08** and **09**.

**Support for the original proposal:** Three of the four respondents supported the overall objective of the modification.

**Opposition:** One respondent opposed the modification, citing that recent industry developments (REMA and the Ofgem charging review) may have overtaken the need for the proposed change and also raised concerns about the modification not promoting effective competition.

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**Other options:** Another option was discussed to extend the scope to Non-Final Demand Users. This was later ruled out of scope for this modification, as noted in the “Consideration of Other Options” section of this report.

### Charging Period (4–7pm all year vs. 24/7)

There was general support for the 4–7pm charging period all year-round as an improvement over the current CUSC baseline. One respondent supported the 24/7 charging period option noting that it avoids perverse incentives to shift Demand into peaks.

*Workgroup feedback:* The Workgroup debated whether charges should reflect year-round system use vs. peak-driven costs but generally agreed that 4–7pm all year-round was preferable and will be reflected in the proposed legal text.

### Use of Average Consumer Profiles

There was general support in the Workgroup Consultation for using average consumer profiles as the best estimate and most reasonable assumption for determining the relevant charging periods.

*Workgroup feedback:* The Workgroup agreed and noted that using average consumer profiles had been debated in previous Workgroups and that no significant objections were raised.

### Symmetry of Positive vs. Negative Charges

The Workgroup Consultation feedback indicated that the arrangements in positive charging zones should not be amended as part of this modification and should remain on the baseline.

*Workgroup feedback:* The Workgroup debated whether or not charging periods should align for positive and negative charges. The Proposer of the original solution and the Proposer of WACMI commented that charging in positive zones works well under the current design and should not be altered unnecessarily.



## Public

The consensus amongst Workgroup members was to leave positive charging arrangements unchanged, as no defect had been identified.

## Post Consultation Workgroup Discussion

### Further Legal Text discussions and clarifications

The Workgroup discussed how revenue from negative zones should be spread across the residual, clarifying current practice and identifying mismatches between wording and calculations. The wording was improved in creating the legal text for CMP440 to make clearer that the surplus that accrues from flooring the Demand locational in negative charging zones, under this modification and the WACMI solution, only for Non-Final Demand, comes off the value of the Transmission Demand residual.

The Proposers of the original and of WACMI reviewed and debated specific legal text sections, including the current use of "de minimis" to convey an intended meaning of flooring a value at zero, the handling of Non-Final Demand customers, and ensuring correct references and calculations throughout.

The intended working of WACMI in relation to the calculation of the p/kWh tariff for use in what would in £/kW terms have been negative charging zones was discussed with the Proposer; there was no intention to have two tariffs, with the same p/kWh value applying to NHH and HH Demand in such zones, calculated in the one new formula.

Further work was assigned to clarify and update these sections within the legal text, which were completed.

The Workgroup discussed the need to ensure that tariff calculations and definitions are consistent and accurate, especially regarding pence per kWh and pounds per kW conversions and required information from Suppliers for Demand forecasts used in tariff monthly billing and tariff forecasts.

The Workgroup clarified the use of a minimum (floor) Demand charge of £0/kW for HH metered Non-Final Demand and discussed whether NHH metered Non-Final Demand exists. The consensus was to include a provision covering NHH metered Non-Final Demand for completeness, albeit that such customers are rare or may be non-existent.

There was a discussion about how unmetered supplies are classified and charged. The NESO Subject Matter Expert (SME) explained that unmetered Demand is included



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in either HH or NHH categories depending on Settlement classification and is included in the billing system volumes. The Proposer suggested unmetered supplies should default to Final Demand treatment.

The Workgroup questioned the need for a floor on the TDR, as it is unlikely to go negative. The NESO Representative has confirmed that there is no floor on the TDR under baseline (and the specifications of CMP440 original and WACM1, do not propose introducing one).

There was a technical discussion about whether the Non-Recovered Revenue Tariff (NRRT) term is needed as a component in the formula for TDR within the legal text to ensure correct revenue recovery, especially for Non-Final Demand. The NESO Representative agreed to review the formula to confirm if it is required or if it would result in double counting and has concluded that it is required.

Regarding calculation of tariffs in positive and negative charging zones, the Workgroup clarified that, for WACM1, a single pence/kWh tariff is applied in negative charging zones, while the original solution uses separate tariffs for HH and NHH customers. Both Proposers agreed to ensure this distinction is clearly described in this report.

The Workgroup discussed the need for forecasts to be split by final and Non-Final Demand, and for the correct data to be collected for both WACM1 and the original solution. The NESO SME confirmed that Final and Non-Final Demand tariffs would be required.

## Operational signal and data tables

The WACM1 Proposer presented new tables to illustrate operational signals under different scenarios and identified discrepancies in some data that had been included within this report, requesting updates from the original Proposer. The importance of using actual published tariff data was agreed upon by the Workgroup.

## Implications of wasting energy

The Workgroup debated the implications of wasting energy, especially in negative charging zones, and whether it is always undesirable, with distinctions made between low carbon and non-low carbon sources.

The Proposer noted that while wasting energy is generally seen as undesirable, the context changes if the system is running entirely on low-carbon sources (e.g. high

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renewables, no fossil fuels). In such scenarios, provided it costs more to curtail wind or solar than to "waste" energy (e.g. by encouraging Demand to turn up even if not needed), wasting energy may not be as negative as might seem intuitive.

The WACMI Proposer added that the system location matters. If excess renewable energy in negative charging zones could be used elsewhere (e.g. transferred South), then encouraging Demand to "waste" energy locally might not be optimal. The distinction is whether the energy could have been usefully consumed elsewhere or not.

The NESO representative reflected on the meaning of "waste energy," noting that if Demand is artificially created with no useful work being done by way of that consumption (e.g. just running a boiler for no purpose, as an energy "sink"), it has no utility, reinforcing the need to consider the value of the energy use.

A Workgroup member cautioned against making value judgments about what constitutes "useful" energy use in the context of code modifications, suggesting this report should avoid getting entangled in such debates.

The Workgroup agreed to include the Proposer's wording in the Workgroup Report, highlighting that the undesirability of wasting energy is context-dependent, especially regarding the carbon intensity of the generation mix.

## **Transition from HH/NHH terminology to charging based on measurement class and actual Demand post-MHHS**

The Proposer explained that post-MHHS, charging will be based on measurement class rather than whether a customer is currently HH or NHH. As MHHS rolls out, all customers will eventually be settled HH, but the charging methodology will depend on the type of metering (e.g. Current Transformer (CT) Meters for non-domestic customers).

The NESO SME clarified that measurement class will no longer be an industry item after MHHS, so charging will be determined by metering type: non-domestic customers with CT meters will be billed under the HH methodology (Triad), while all whole current metering and domestic customers will be billed under the four-to-seven methodology. Some sites will move between charging methodologies as a result.

The original and WACMI Proposers discussed the need to clarify terminology in the Workgroup report and legal text, noting that references to "HH" and "NHH" are

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becoming outdated. Instead, the report should refer to customers charged on "chargeable Demand location capacity" and "chargeable energy capacity," which better reflect the post-MHHS arrangements.

The NESO SME added that these terms already exist in the baseline and do not map perfectly to HH/NHH status, as some measurement classes (F and G) are technically HH but charged under the four-to-seven methodology.

The Workgroup agreed that further legal text changes to update terminology should be handled separately as a future fast-track modification, rather than as part of the current modification, since the ambiguity exists regardless of the proposed changes.

### **Further discussions on background analysis and interpretation**

The WACMI Proposer summarised the Frontier/LCP analysis, which used a stochastic Dispatch Model and a Transport Model to assess whether peak Demand is still the main driver of network costs. The analysis sampled 96 hours out of the year to represent system conditions, but the selection of these hours and the definition of "representative" (e.g., within 90% of peak flow) introduces subjectivity and limitations.

The WACMI Proposer noted that the current peak and year-round backgrounds are not highly representative of most circuits' peak flows. In some cases, peak flows occur at lower Demand periods, especially in negative charging zones with high wind and export via Interconnectors, suggesting that network reinforcement is not always driven by peak Demand.

The WACMI Proposer argued that the existing analysis does not support the idea that only Demand at peak (e.g. Triad) drives network investment, especially in negative charging zones. Instead, base load Demand or Demand coinciding with high wind periods is more relevant. They cautioned against using the analysis to justify a narrow charging base focused only on peak Demand.

The original Proposer emphasised that the key factor in the model is the direction of flow (whether Demand increases or decreases network flows), not the magnitude at a specific time. They noted that both peak and year-round backgrounds are set at peak Demand, and the main impact is on whether a User is classified as contributing to or reducing flows, not the exact Demand level.

## Public

The Workgroup agreed that the report should present both the original Proposer and the WACM1 Proposer’s interpretation, noting that the chain of logic regarding backgrounds is a matter of opinion, not fact.

## Alternative Requests

Prior to the Workgroup Consultation one Alternative Request was submitted by a Workgroup Member (**Annex 04**).

This request sets out the case as to why the Workgroup member who submitted it wished to amend parts of the original Proposal.

The Workgroup reviewed the request, and the table below provides an overview of the outcome:

Solution and Outcome of Alternative Vote	Party	Characteristic	Mechanism of Workgroup Vote
Alternative Request 1 ( <b>WACM1</b> )	Statkraft UK Ltd	Charging over all periods to avoid negative price incentives.	Voted in by Workgroup (Workgroup 10).

Other ideas for alternatives were discussed as per the section below “Consideration of other options” but were not officially raised or voted on by the Workgroup.

## WACM1 - Charging over all periods to avoid negative price incentives

**Overview:** WACM1 proposes that for TNUoS zones where the total Demand locational signal is negative, locational TNUoS is converted into a p/kWh figure and charged across total year-round Demand. For simplicity, a single common rate is calculated for NHH and HH.

The WACM1 Proposer contends that the original solution would result in a strong distortive signal for Demand in Scotland to increase or shift to a large number of peak settlement periods – the type of perverse incentive that the introduction of the floor was trying to avoid in the first place. WACM1 avoids this by spreading the negative Demand locational signal across all periods of Demand, not just peak periods.

NESO’s CP30 document highlights that the major (£60bn) Transmission investments required to achieve a low carbon electricity system are largely driven by avoidance of

## Public

constraint costs. In addition, the TNUoS model calculates that 95% of the negative signals output from the model relate to year-round, not peak circuits.

Charging across year-round is more consistent with the negative Demand signal outputs from the TNUoS model, but more importantly, are a better proxy for the real-world drivers of grid infrastructure investment.

WACMI avoids perverse operational incentives and is more cost reflective of the savings that result of Demand being in negative zones.

**Workgroup discussion:** Workgroup members expressed that the WACMI proposal was clear, well-presented, and compelling, with no questions or objections raised.

The WACMI Alternative Request form can be found in **Annex 04** and a slide presentation on this in **Annex 05**.

## Consideration of other options

A Workgroup observer introduced a further alternative idea during the Workgroup discussions, which was not officially proposed to be a potential Alternative Request. As there are significant implications for DNOs and embedded Generators among other issues in this idea, it goes beyond the scope of the original modification proposal. This was confirmed by both the NESO Code Administration Team and the NESO Legal Team. The idea that was proposed and Workgroup discussion around it is set out below:

### Enhancing locational signals in TNUoS: A Workgroup proposal for Demand attraction in high generation areas

**Workgroup discussion:** The proposed solution aimed to strengthen locational signals in the TNUoS charging methodology to attract large-scale, flexible Demand Users to areas with high generation, particularly renewables.

With regards to the expected Impact, it was noted that increased Demand in high-generation areas would, over time, weaken both negative Demand and highly positive generation locational signals, leading to tariff evolution. While unlikely to incentivise domestic customers to relocate, it could drive industrial growth and associated residential/Small Medium Enterprise (SME) Demand.

## Public

The DNO would be responsible for responding to TNUoS signals on behalf of embedded Demand, passing costs through DUoS charges. This approach was seen as efficient, assuming DUoS is functioning correctly.

The proposed solution suggested that TNUoS tariffs should use the load factor of the connecting asset and be applied to Demand connection or agreed capacity. For negative tariffs, the average of three maximum Demands would be used, consistent with generation TNUoS charging.

The proposed solution would require updates to the DCUSA and potentially DNO licenses.

**Workgroup Conclusion:** The Workgroup acknowledged the efficiency and equity of charging Demand in the same way as generation but noted that implementing such changes would require significant industry and regulatory updates and was outside the scope of the current modification, and so was not progressed as an alternative solution.

## Other suggestions

Some Workgroup members proposed extending the scope of the modification to include Non-Final Demand Users. This was debated but ultimately ruled out of scope for CMP440, with the suggestion that it could be raised as a separate modification in the future.

## Terms of Reference Overview

### a) Consider EBR implications

The Workgroup noted that Article 18 of the Electricity Balancing Guideline (EBGL) is specifically about frequency restoration and replacement reserves, and the modification is not relevant to this, therefore there are no EBR implications.

### b) Consider whether the peak charge should apply to winter or all year?

It was decided that the Demand locationals (peak and year-round alike as they are not treated differently under this modification) should apply to 4-7pm all year round in the original; and to all periods of the year in WACM1.

## Public

- c) Consider whether the year-round charge should apply all day or just 4-7pm?

It was decided that the Demand locationals (peak and year-round alike) should apply to 4-7pm all year round in the original; and to all periods of the year in WACM1.

- d) Consider whether positive and negative Demand charges should be charged differently i.e. keep the existing methodology for positive Demand charges?

Any change to the current application of positive Demand locational TNUoS charges was regarded as out of scope of this modification.

- e) Consider what the methodology should be for conversion from £/kW to p/kWh? (Inclusive of any practical impact on the design choices)

The Proposer discussed a more conservative approach to this conversion (in respect of assumed load factor) than is presently used in converting £/kW Demand locationals into p/kWh charges for NHH TNUoS-settled Demand. However, the Workgroup decided to maintain the present neutral approach based on average load factors.

## What is the impact of this change?

CMP440 will primarily impact electricity Suppliers and directly connected Demand Users, especially in the North of Great Britain, by changing how TNUoS locational Demand tariffs are applied—removing the zero-price floor and allowing negative locational charges to be credited from 01 April 2027. This change will restore cost-reflective locational signals for Demand but will also require an increase in the TDR charge for all Demand customers to maintain revenue neutrality, meaning some Users may see higher costs. The main positive impact is the reintroduction of efficient investment signals and reduced risk of perverse incentives, while the main negative impact is increased complexity and potential cost shifts for some customer groups



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## Original and Workgroup Alternative Proposer's assessment against Code Objectives

Original Proposer's assessment against the CUSC Code Objectives	
Relevant Applicable 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;	<b>Positive</b>  Would re-introduce a cost-reflective incentive for Demand investment and economic growth resulting from reduced network congestion and Transmission investment requirements.
(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 C26 requirements of a connect and manage connection);	<b>Neutral</b>  Will not impact cost recovery but will re-distribute charges between Demand Users according to their relative cost impact on the Transmission System.
(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, properly takes account of the developments in Transmission licensees' Transmission businesses;	<b>Positive</b>  Would increase cost-reflectivity of Transmission investment requirements.
(g) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	<b>Neutral</b>  No impact. Re-introduces a cost signal that was in place before April 2023.
(h) Promoting efficiency in the implementation and administration of the system charging methodology.	<b>Positive</b>  Reduction of the use of Triads for charging and alignment of charging periods for NHH and HH customers simplifies charging.

## Public

*\*\*The Electricity Regulation referred to in objective (g) 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.*

Relevant Applicable Objective	WACM1 Proposer's assessment
(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;	<b>Positive</b>  This WACM is better than the status quo as it reinstates negative TNUoS locational signal in areas where locating Demand will reduce system costs. It is more positive than the original as it does not introduce any distortive behaviours in Demand response.
(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 C26 requirements of a connect and manage connection);	<b>Positive</b>  Reinstating the negative Demand signal is more reflective, as the implied Transmission savings are not currently being recognised since the floor was implemented. This WACM is more reflective than the original proposal as it distributes the negative charges over periods that better reflect the system savings.
(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, properly takes account of the developments in Transmission licensees' Transmission businesses;	<b>Neutral</b>
(g) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	<b>Neutral</b>
(h) Promoting efficiency in the implementation and administration of the system charging methodology.	<b>Positive</b>  The solution in this WACM is simple and is consistent with existing approaches.
<i>**The Electricity Regulation referred to in objective (g) is Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity</i>	

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*(recast) as it has effect immediately before IP completion day as read with the modifications set out in the SI 2020/1006.*

## Workgroup Vote

The Workgroup met on 09 December 2025 to carry out their Workgroup Vote. The full Workgroup Vote can be found in **Annex 10**. The table below provides a summary of the Workgroup Members view on the best option to implement this change.

For reference the Applicable CUSC (charging) Objectives are:

- 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;*
- 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);*
- 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, properly takes account of the developments in Transmission licensees' Transmission businesses and the ISOP business\*;*
- g) *Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency \*\*; and*
- h) *Promoting efficiency in the implementation and administration of the system charging methodology.*

*\* See Electricity System Operator Licence*

*\*\*The Electricity Regulation referred to in objective (g) 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.*

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The Workgroup concluded by majority (out of 6 votes) that the original and WACMI better facilitated the Applicable Objectives than the Baseline.

Option	Number of voters that voted this option as better than the Baseline
Original	5
WACMI	5

## When will this change take place?

### Implementation date

01 April 2027 (adequate time is required for Suppliers to anticipate changes to customer tariffs including the default tariff cap).

### Date decision required by

30 September 2026

### 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.

## Interactions

- |  |  |   |  |
|--|--|---|--|
| <input type="checkbox"/> Grid Code                 | <input type="checkbox"/> BSC                                 | <input type="checkbox"/> STC                    | <input checked="" type="checkbox"/> SQSS |
| <input type="checkbox"/> European<br>Network Codes | <input type="checkbox"/> EBR Article 18<br>T&Cs <sup>1</sup> | <input type="checkbox"/> Other<br>modifications | <input type="checkbox"/> Other           |

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

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## Acronyms, key terms and reference material

Acronym / key term	Meaning
ACO	Applicable CUSC Objectives
ACS	Average Cold Spell
ALF	Annual Load Factors
BCA	Bilateral Connection Agreement
BEGA	Bilateral Embedded Generation Agreement
BELLA	Bilateral Exemptible Large License-exempt Generator Agreement
BSC	Balancing and Settlement Code
BSUOS	Balancing Services Use of System
CCGT	Combined Cycle Gas Turbines
CCL	Climate Change Levy
CMP	CUSC Modification Proposal
CT	Current Transformer
CUSC	Connection and Use of System Code
DCUSA	The Distribution Connection and Use of System Agreement
DESNZ	Department for Energy Security and Net Zero
DNO	Distribution Network Operator
DUoS	Distribution Use of System
EBGL	Electricity Balancing Guideline
EBR	Electricity Balancing Regulations
EET	Embedded Export Tariff

## Public

EII	Energy Intensive Industries
ETYS	Electricity Ten Year Statement
FES	Future Energy Scenarios
GSP	Grid Supply Point
GTNUoS	Generator Transmission Network Use of System
HH	Half hourly
HVDC	High Voltage Direct Current
ICRP	Investment Cost Related Pricing
kW	Kilowatt
kWh	Kilowatt-hour
LRMC	Long Run Marginal Cost
MHHS	Market Wide Half Hourly Settlement
MW	Megawatt
MWKM	Megawatt-kilometre
NCC	Network Charging Compensation
NESO	National Energy System Operator
NHH	Non-Half Hourly
NRRT	Non-Recovered Revenue Tariff
OCGT	Open Cycle Gas Turbine
OHL	Overhead Line
REMA	Review of Electricity Market Arrangements
SME	Small Medium Enterprise
SME	Subject Matter Expert

## Public

SRMC	Short Run Marginal Cost
SQSS	Security and Quality of Supply Standards
STC	System Operator Transmission Owner Code
TCR	Targeted Charging Review
TDR	Transmission Demand Residual
TEC	Transmission Entry Capacity
TNUoS	Transmission Network Use of System
T&Cs	Terms and Conditions
WACC	Weighted Average Cost of Capital
WACM	Workgroup Alternative CUSC Modification

## Reference material

- [Ofgem's decision from the Targeted Charging Review](#)
- CMP343 Transmission Demand Residual bandings and allocation for 01 April 2022 implementation:
- <https://www.nationalgrideso.com/industry-information/codes/cusc/modifications/cmp343-and-cmp340-transmission-Demand-residual-bandings-and-allocation-1-april-2022-implementation-cmp343-and-consequential-changes-cmp343-cmp340>
- CMP213 Project TransmiT TNUoS Developments:
- <https://www.nationalgrideso.com/industry-information/codes/cusc/modifications/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



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- 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

Annexes	
Annex	Information
Annex 01	CMP440 Proposal form
Annex 02	CMP440 Terms of reference
Annex 03	CMP440 Original and WACMI Legal Text
Annex 04	CMP440 WACMI Alternative Request Form
Annex 05	CMP440 Slide presentation of WACMI
Annex 06	CMP440 Tariff Calculations for WACMI
Annex 07	CMP440 Effective Price Signals for WACMI
Annex 08	CMP440 Workgroup Consultation Responses (Non-Confidential)
Annex 09	CMP440 Workgroup Consultation Summary
Annex 10	CMP440 Alternative and Workgroup Vote
Annex 11	CMP440 Workgroup Action Log
Annex 12	CMP440 Workgroup Attendance Record