Public

CMP440

Workgroup 1, 08 January 2025

Online Meeting via Teams

NESO National Energy System Operator

WELCOME

Agenda

Topics to be discussed	Lead
Introductions	Chair
Code Modification Process Overview • Workgroup Responsibilities • Workgroup Alternatives and Workgroup Vote	Chair
Objectives and Timeline • Walk-through of the timeline for the modification	Chair
Proposer presentation	Proposer
Questions from Workgroup Members	All
Agree Terms of Reference	All
Cross Code Impacts	All
Any Other Business	Chair
Next Steps	Chair

Modification Process

Teri Puddefoot – NESO Code Administrator

Code Modification Process Overview

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

Talk to us	Raise a mod	Refine solution	Consult	Decision	Implement
Forums	Panels	Workgroups (Workgroup Consultations)		Ofgem/Panel	

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Refine Solution

Workgroups

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

Consult
Code Administrator Consultation

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

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

Decision

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

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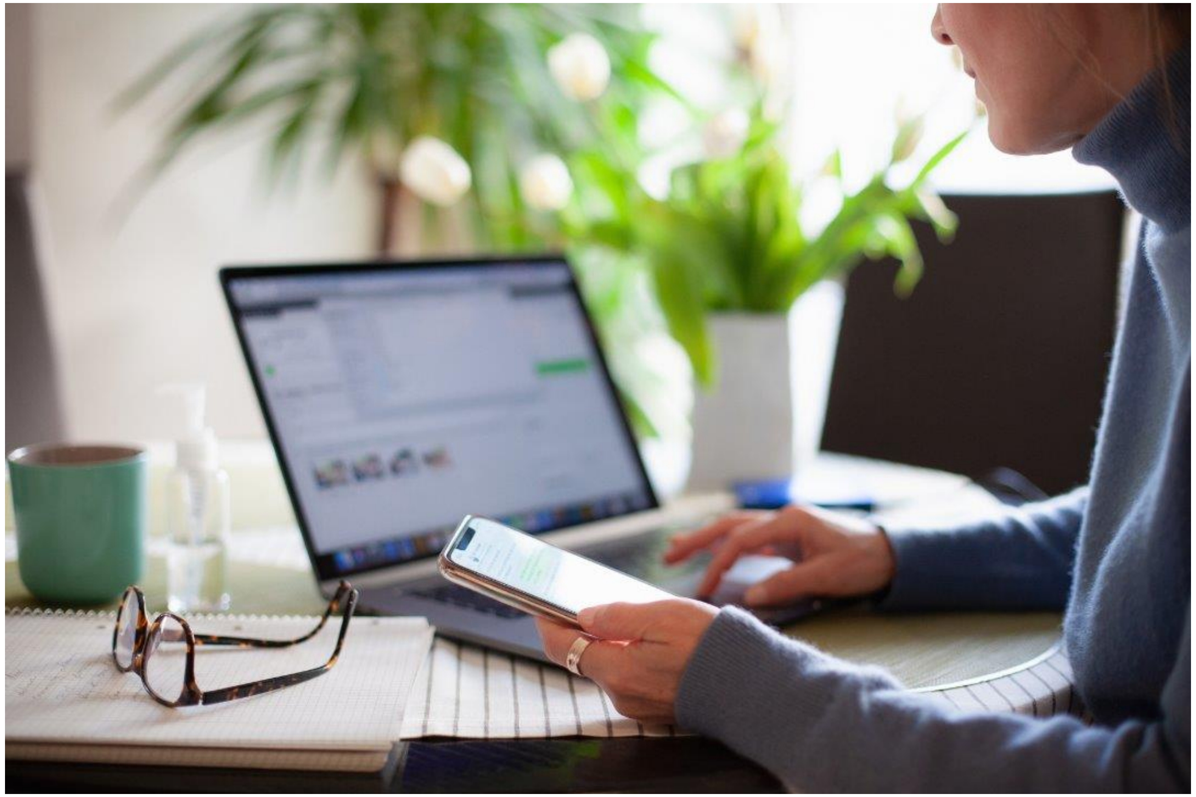
Implement

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



Workgroup Responsibilities and Membership

Teri Puddefoot – NESO Code Administrator

Expectations of a Workgroup Member

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

Your Roles

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

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Workgroup Membership

Role	Name	Company
Proposer	Lauren Jauss	RWE
Workgroup Member	Robert Longdon	Cornwall Insight
Workgroup Member	Karl Maryon	Drax
Workgroup Member	Simon Vicary	EDF
Workgroup Member	George Douthwaite	ITP Energised
Workgroup Member	Ana Gorgyan	Independent Power Corporation PLC
Workgroup Member	Alex Savvides	Stratkraft
NESO Representative	Ruby Pelling	NESO
Authority Representative		

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Objectives and Timeline

Teri Puddefoot – NESO Code Administrator

Timeline for CMP440 as at November 2024 (Panel)

Milestone	Date	Milestone	Date
Modification presented to Panel	27 September 2024	Workgroup 10	
Workgroup Nominations (15 business Days) 15 clear business days minimum	04 October 2024 to 01 November 2024	Workgroup 11	
Workgroup 1 etc..	08 January 2025	Workgroup 12?	
Workgroup 2	23 January 2025	Workgroup report issued to Panel (5 business days) 5 clear business days minimum	16 June 2025
Workgroup 3	11 February 2025	Panel sign off that Workgroup Report has met its Terms of Reference	26 June 2025
Workgroup 4	27 February 2025	Code Administrator Consultation	01 July 2025 to 22 July 2025
Workgroup 5	11 March 2025	Draft Final Modification Report (DFMR) issued to Panel (5 business days) 5 clear business days minimum	14 August 2025
Workgroup 6	31 March 2025	Panel undertake DFMR recommendation vote	22 August 2025
Workgroup Consultation (15 business days)	07 April 2025	Final Modification Report issued to Panel to check votes recorded correctly Ideally issued within 2 business days of Panel's DFMR recommendation vote. They have 5 clear business days to check.	28 August 2025
Workgroup 7 etc –	DD Month Year	Final Modification Report issued to Ofgem This is clear 5 business days after Final Modification Report is issued to Panel to check votes recorded correctly	03 September 2025
Workgroup 8		Ofgem decision (X business days) Typically TBC or decision requested/needed by DD Month Year	30 September 2025
Workgroup 9		Implementation Date Typically 1 April date if a CUSC charging change; 10 business days after Ofgem decision for anything else. There are exceptions depending on the change itself.	01 April 2026

Proposer’s Solution: Background; Proposed Solution; Scope; and Assessment vs Terms of Reference

Lauren Jauss – RWE

RWE

Overview of:

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

Lauren Jauss (Proposer)
Workgroup 1, 8th Jan 2025

Context

- The TNUoS Taskforce were asked to consider:
  - Is it appropriate to have negative locational charges for demand?
  - Should the floor at zero be reviewed?
  - What signals should demand TNUoS send, and how?

- Taskforce agreed on the following high-level principles:
  - Demand and generation negative locational charges are appropriate, but there should not be a negative total cost of final demand to a consumer to incentivise them to waste energy in a specific time period
  - Ideally, generation and demand locational signals would be approximately equal and opposite
  - TNUoS should not send operational signals, as this can be better achieved through other mechanisms.
  - TNUoS should reflect the long-run incremental investment cost impact on the transmission system from <u>long-term user investment decisions</u>

- Frontier were commissioned for several TNUoS studies including consideration of the design principles that should underpin locational demand charges, and the extent to which the current design of demand charges remains fit for purpose. The following slides are selected from Frontier’s presentations to the Taskforce

Peak and Year Round type backgrounds are important but their representation potentially can be improved with changes to the assumed generation mix (2025)

Cost reflectivity

	Current backgrounds		Most representative backgrounds (2025, NGESO FES ST scenario)		
Technology	*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

Representative backgrounds identified (2025)

- In the identified representative backgrounds, the percentage shown is the average load factor observed for the particular technology in that scenario from LCP's dispatch modelling.
- The most representative background observed, shown as "Round 1", gives a 'good' representation of 59% of circuits.
- The "Round 1" background is somewhat similar to the year-round background, with high wind, biomass and nuclear load factors, and lower gas generation.
- "Round 2" gives the greatest increase to representation of circuits when combined with Round 1. Round 2 is somewhat similar to peak, but with variation in load factors across the fleet and interconnectors importing.
- "Round 3" has lower demand and high wind load factors leading to demand from pump storage and export via interconnectors.

Backgrounds, Taskforce Meeting 6, 26th June 2023

…our analysis suggests that updates to the current backgrounds could be appropriate in order to improve cost reflectivity

Cost reflectivity

- The analysis suggests that Year Round and Peak Security type backgrounds are likely to remain relevant, though their representativeness can be improved with changes to specific assumptions.
- If a single background was favoured, a Year Round type scenario could be most appropriate going forward, although this could entail a small reduction in cost reflectivity, relative to two backgrounds. For example, charges would be expected to increase for wind as circuits previously tagged to Peak Security are now tagged as Year Round.
- The marginal benefit of adding a third background is much reduced compared to adding a second background, particularly in 2035.
- Irrespective of whether this analysis is considered to support a change, an update to the backgrounds is likely to be required in future e.g. due to “fixed” generation exceeding demand.

Level of charges

- The impact of using more representative backgrounds appears to be relatively limited, either using two alternative backgrounds or a single alternative.
- This suggests that without a change to the fundamental flow from North to South, changes to backgrounds may only have a limited impact on final charges.
- In addition, if the €2.50/MWh cap is binding then the adjustment tariff may also reduce the impact of changes further.

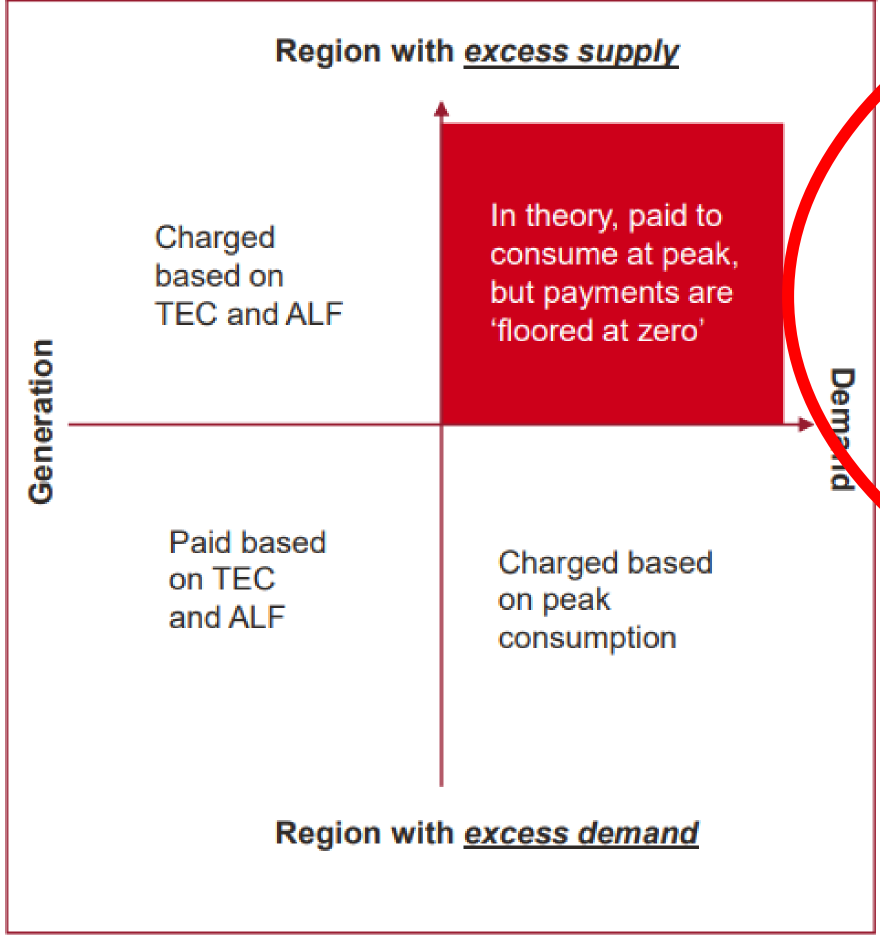
Predictability of charges

- The predictability analysis suggests that there are no clear implications for year to year volatility from applying one (Year Round) or two backgrounds, which may suggest no material change in predictability of the tariffs.
- Although moving to a single background would remove one area of uncertainty in the tariff calculations (i.e. the tagging of circuits to a particular background).
- There appear to be volatility implications if adopting only a peak background, however, this would be inconsistent with the cost reflectivity analysis.

…however, our initial view is that the implications of change for the level and volatility of charges may be relatively limited

Concerns that led to "floored at zero" are less relevant if the operational signal is much diluted

Charges are currently "floored at zero"

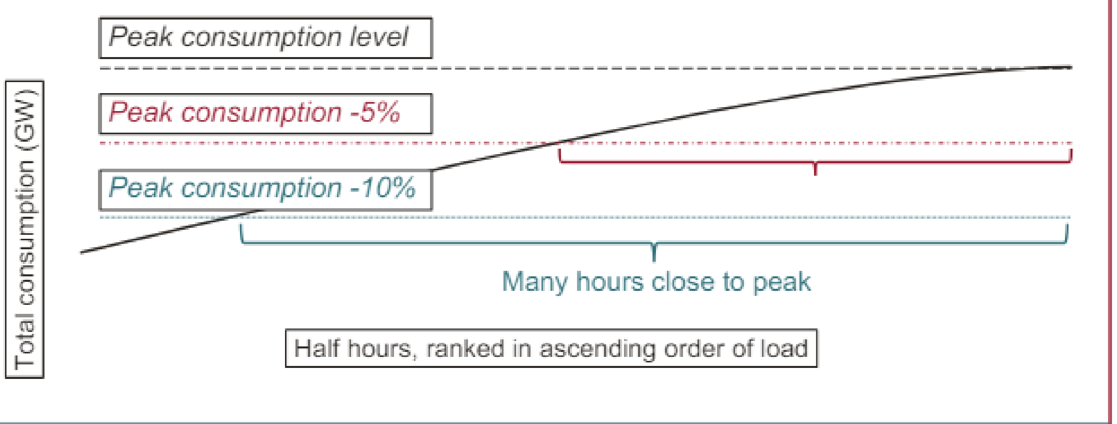


Removing floored at zero would restore important investment signal

- Charges currently floored at zero, to avoid incentivising increased peak consumption, which Ofgem worries will impact on security of supply.
- It leads to **inefficient investment signals** – Demand is insufficiently incentivised to locate close to sources of supply.
- If significantly reducing / removing operational signals then floored at zero is much less of a concern.
  - If setting charges based on a broad base of hours, incentive to increase demand remains but it is much diluted so less likely to be of concern
  - If setting charges based on deemed consumption/banding then operational signal removed
- From an efficiency perspective, removing floored at zero is beneficial.

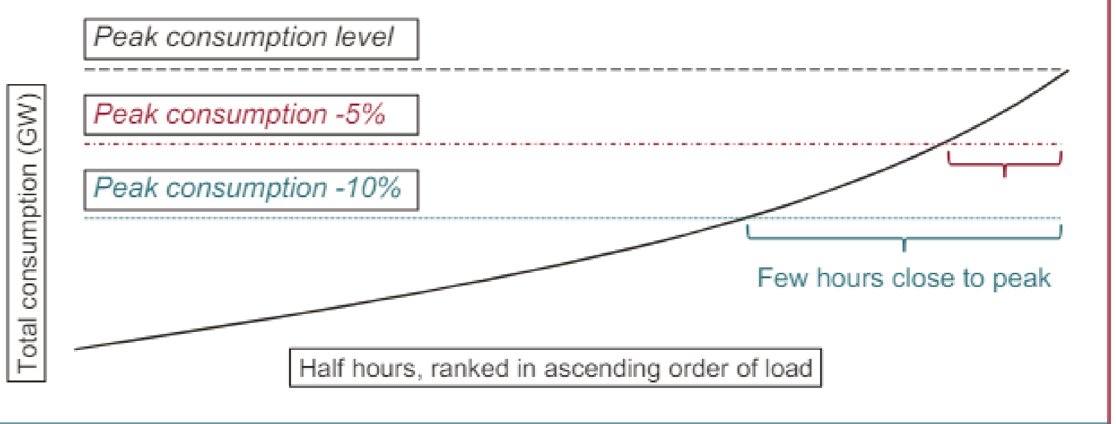
When choosing appropriate Peak Security charging methodology, it is important to consider the gradient of the load duration curve

Shallow load duration curve:



- Broad base of hours where consumption is close to peak i.e. consumption across many hours is important potential drivers of future Peak Security costs.
- This suggests that **demand should be charged** (penalised/rewarded) on the basis of **consumption across a broad base of peak hours.**

Steep load duration curve

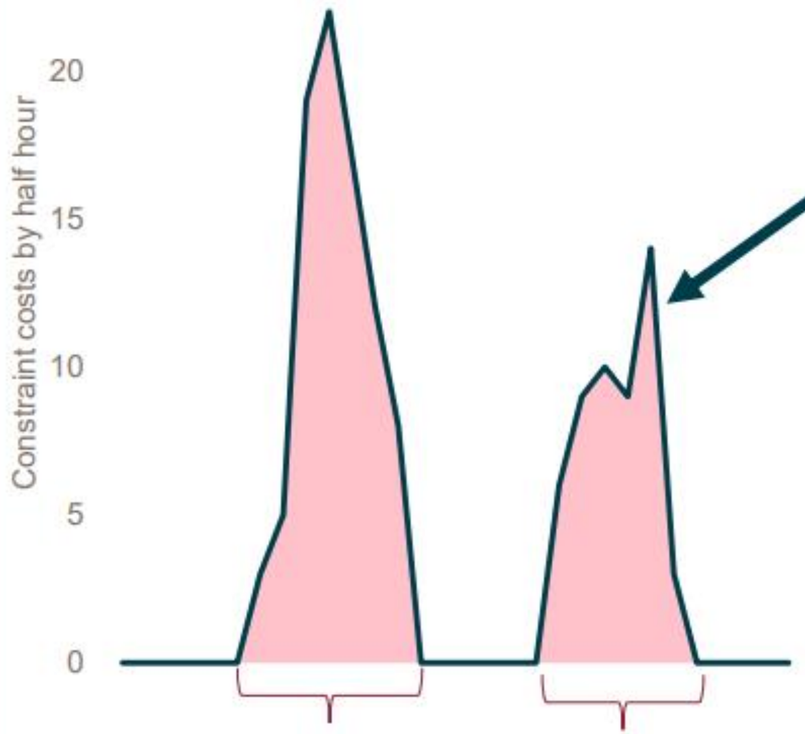


- Relatively few hours where consumption is close to peak i.e. consumption across only a few hours is important potential driver of Peak Security costs.
- This suggests that **demand should be charged** (penalised/rewarded) on the basis of **consumption in only a few peak hours**

Ultimately, the shape of demand is an empirical question which could be investigated further (see slide 30)

All constrained hours are relevant for year-round costs, rather than just hours of maximum constraint

Hypothetical constraint costs over time



Periods that contribute to constraint costs

Year-round costs relate to the sum of constraint costs

- Year-round costs relate to the optimal network investment required to efficiently alleviate constraint costs.
- Constraint costs vary over time, as represented by the line in the graph.
- Network investment to alleviate constraint costs is **not driven by the peak level** of constraint costs, rather it is driven by the total of constraint costs across all periods, as represented by the pink shaded area.

All constrained hours are relevant but not equally

- A 1MW increase in demand will have an impact on constraint costs in **all hours that the network is constrained.**
- However, the marginal cost of alleviating constraints in each constrained hour will vary depending on the actions the ESO must take to resolve the constraint.
- It is likely that when constraints are larger overall (deeper), the marginal cost to resolve the constraint will be larger because the ESO will have already exhausted the cheaper options for alleviating constraint

Basic options for charging year round identifying which hours and allocating year-round costs

1 Average demand in all hours

- Simple to implement
- Easy to understand
- Sends minimal (very diluted) operational signal
- Likely more cost reflective than charging based on peak demand
- Abstracts from the distinction between consumption during constrained hours (which affects required network investment), and consumption in other hours (which does not)

Analogous to a Load Factor style approach

Average demand in constrained hours only

2 Unweighted

- Charges based on average consumption during all constrained hours.
- Would send only a small operational signal (assuming there are many constrained hours in a year)
- Sends more targeted cost reflective investment signal but not fully cost reflective.

Analogous to a "Constrained Load Factor" style approach

3 Weighted by a metric

- Charges based on weighted average consumption in constrained hours.
  - Options for weighting approach discussed in slide 26
- May send a modest operational signal in most periods but may send stronger incentives when constraints are higher.
- In principle sends a more targeted and cost reflective investment signal.

Analogous to a "Constrained Load Factor" style approach with further adjustment

We assess each of these options in the following slides

The TNUoS Taskforce's Conclusions and Recommendations

- The Taskforce's objective was to agree key principles and identify any case for change. The Taskforce agreed that:
- The zero-floor removes important investment incentives and there is therefore a case for change
- Given the importance of locational demand investment signals as cited in the REMA consultations and ESO Beyond 2030 report, this case for change would seem to be of relatively high priority (to which the CUSC Panel have agreed, having prioritised this modification as high)
- Charges based on actual consumption over a broader base of hours for both Peak and Year-Round Tariffs would reduce the operational signal which would in turn reduce the rationale for the floor.
- Further analysis is expected to be relatively detailed and could be conducted during the CUSC change process
- For Year-Round Tariffs in particular, the Taskforce considered Frontier's Option 1 to be the best solution:
- Option 1 appears most consistent with the approach used for generation charging, which also considers consumption across the whole year and does not weight charges by generation during periods of constraints
- Options 2 & 3 would make Demand TNUoS charges less predictable as they would be dependent on constraints for which Users have limited data and no control. The definition and identification of "constrained hours" is very complex

Taskforce recommended scope for a CUSC modification

- Taskforce recommend a modification to apply to Final Demand only, highlighting that:
  - Transmission connected/large 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, but this is unlikely to be appropriate
  - Distribution connected generators are to be considered separately by Ofgem with recommendations from the Distributed Generation Sub-group of the TNUoS Taskforce. Hence the Embedded Export Tariff is similarly out of scope.
  - Storage demand is to be considered by the new Storage TNUoS Sub-group.
- Electrolysers are an important future source of demand that expected to be able to respond to long term locational cost signals to some extent. It is not clear at this stage whether electrolyser demand will be included in the definition of Final Demand. If excluded, the scope of changes under this mod should be revisited so as to include electrolysers

Converting the £/kW Tariff to p/kwh for Half-Hourly customers
Outstanding Issue & Problem Statement

- If we intend to levy charges over a wider period of consumption, rather than peak offtake, we need a p/kwh tariff rather than a £/kW tariff
- The transport model outputs £/kW - how do we convert this to p/kwh? What are the principles?
- The current approach for NHH customers is to consider, by GSP Group, the forecast income from those customers if the £/kW tariffs were levied at triad. The p/kwh tariff is set so it recovers the same income from energy consumption over the charging period (4-7pm all year)
- There is an inherent assumption that everyone has the same profile. This is not currently a significant issue for NHH customers because they are already deemed to consume in a standard profile (although there are slightly different ratios of chargeable kWh to peak MW consumption across different profile classes)
- If a standard rate is used to convert the kwh consumption of an HH customer over a wider chargeable period to a deemed peak consumption level, this will be much less accurate than the current peak consumption measure at triad

Converting the £/kW Tariff to p/kwh for Half-Hourly customers
Proposed Principles (not necessarily endorsed by Taskforce)

- The current concept is to charge customers based on their ACS Peak consumption/maximum required capacity
- The Economy Criterion allows for a degree of constraints to the extent it would not be economically optimal to build transmission to alleviate them.
- The Year-Round Background scenario represents the Economy Criterion and uses demand at ACS Peak.
- Backgrounds merely establish the prevailing power flows across each circuit, and the Year-Round allows for an optimal level of constraints
- Tariffs are derived from an incremental MW of generation/demand at ACS Peak and are intended to reflect the marginal cost of *firm capacity access i.e. constraints and ALF do not feature at this stage*
- A consumer's ACS Peak consumption is similar to generator TEC where tariffs are derived to be levied on generator Transmission Entry Capacity, not generation output at peak, or indeed across the year
- Intermittent and dispatchable generation is deemed to *share network capacity in order to meet demand* – this is why the Sharing methodology reduces different amount of the generation tariff by a factor equal to ALF
- Hence, it is proposed that maximum/ACS Peak demand remains the basis for Wider Tariff charges because the tariff is reflective of firm capacity access. An equivalent network sharing approach for demand users might consider the extent to which periods of high/ peak demand occur at different times

For Reference - Current Approach for Deriving p/kWh Tariffs

CUSC 14.16 Derivation of the Transmission Network Use of System Energy Consumption Tariff and Short Term Capacity Tariffs

14.16.1 For the purposes of this section, Lead Parties of Balancing Mechanism (BM) Units that are liable for Transmission Network Use of System Demand Charges are termed Suppliers.

14.16.2 Following calculation of the Transmission Network Use of System £/kW HH Locational Demand Tariff (as outlined in Chapter 2: Derivation of the TNUoS Tariff) for each GSP Group a NHH Demand Locational Tariff is calculated as follows:

$$\text{p/kWh Tariff} = \frac{(NHHD_F * \text{£/kW Tariff} - FL_G)}{NHHC_G} * 100$$

Where:

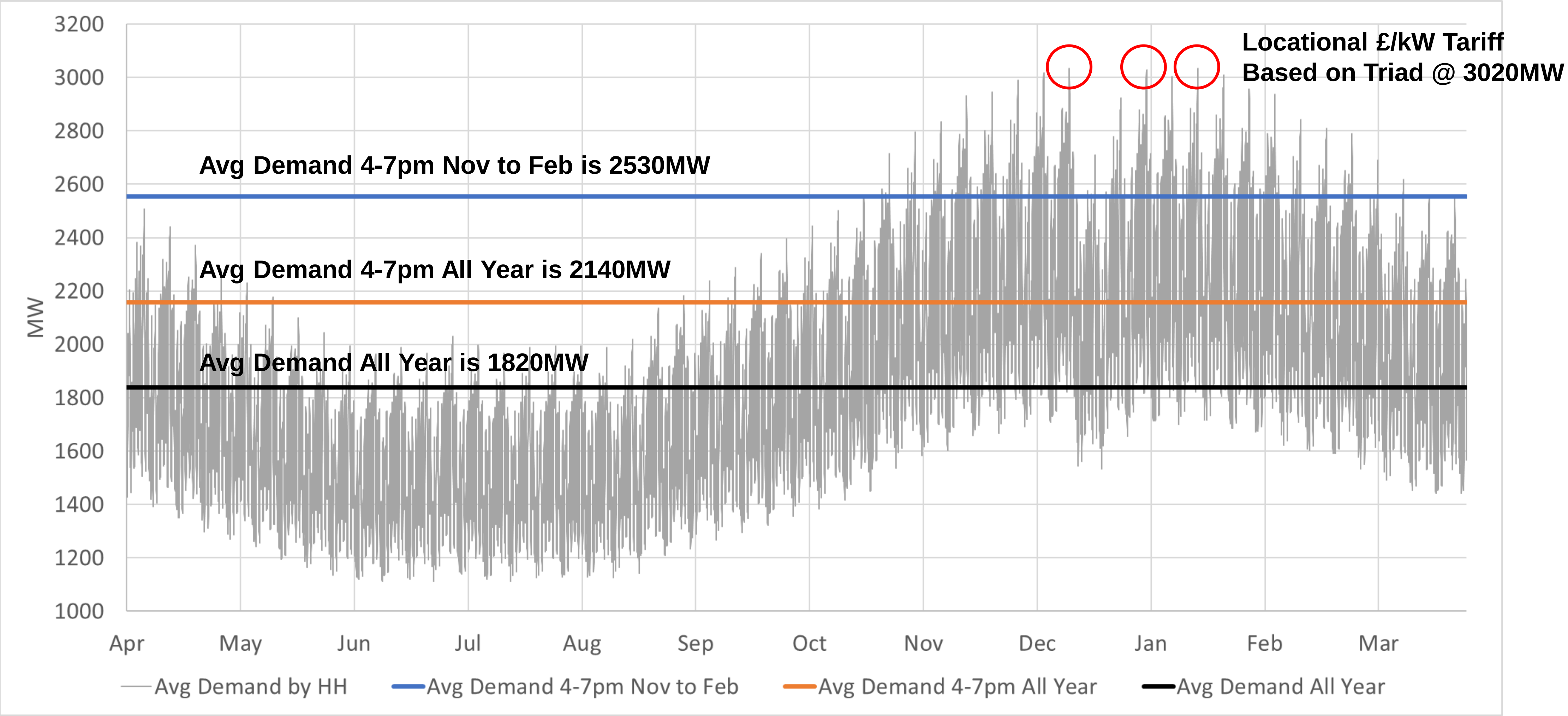
£/kW Tariff = The £/kW Effective HH Demand Locational Tariff (£/kW), as calculated previously, for the GSP Group concerned.

$NHHD_F$ = **The Company's** forecast of Suppliers' non-half-hourly metered Triad Demand (kW) for the GSP Group concerned. The forecast is based on historical data.

FL_G = Forecast Liability incurred for the GSP Group concerned.

$NHHC_G$ = **The Company's** forecast of GSP Group non-half-hourly metered total energy consumption (kWh) for the period 16:00 hrs to 19:00hrs inclusive (i.e. settlement periods 33 to 38) inclusive over the period the tariff is applicable for the GSP Group concerned.

Illustrative Example with Dummy Data (GSP Group H Southern)



Summary of CMP440 Proposal

- It is proposed that:
- The zero price floor be removed for **<u>Final Demand for negative Peak Tariffs</u>** and those negative charges levied on HH and NHH metered energy consumption over the period **16:00 hrs to 19:00 hrs inclusive every day** over the Financial Year i.e. in the same way as NHH consumption is currently charged.
- The zero price floor be removed for **<u>Final Demand for negative Year Round Tariffs</u>** and those negative charges levied on HH and NHH **total annual metered energy consumption.**
- The corresponding negative tariffs in p/kWh are arrived at by scaling the corresponding £/kW Demand Locational Tariff by the ratio of forecast metered consumption over the relevant period **assuming a baseload consumption profile**, so that the negative charge will be based on an underestimate of a user's ACS Peak consumption (as long as their measured consumption is higher than their average consumption across the year)

Current

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

Proposed

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

Agree Terms of Reference

Teri Puddefoot – NESO Code Administrator

Terms of Reference

Workgroup Term of Reference	Location in Workgroup Report (to be completed at Workgroup Report stage)
a) Consider EBR implications	
b) Consider whether the peak charge should apply to winter or all year?	
c) Consider whether the Year-Round charge should apply all day or just 4-7pm?	
d) Consider whether positive and negative demand charges should be charged differently i.e. keep the existing methodology for positive demand charges?	
e) Consider what the methodology should be for conversion from £/kW to p/kWh? (Inclusive of any practical impact on the design choices)	

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Cross Code Impacts

Teri Puddefoot – NESO Code Administrator

Any Other Business

Teri Puddefoot – NESO Code Administrator

Next Steps

Teri Puddefoot – NESO Code Administrator