TNUoS Task Force

Meeting 5

26th April 2023

Agenda

10:00 – 11:45

- > 10:00 Introduction & Welcome
- > 10:05 Ways of Working & Expectations
- > 10:15 Ofgem Update
- > 10:25 Progress to Date
- > 10:45 Analytical Support
- > *11:45 Break*

12:00 – 13:00

- > 12:00 Feedback & Further Discussion
- > 12:30 Forward Looking Plan
- > 12:50 Next Steps & Close

Charging Futures

Ways of Working & Expectations

Jon Wisdom

The objective of this session is to recap on:

- General Ways of Working (WoW)
- How the Task Force process should work
- Expectations of TF members i.e. wider engagement etc

Ways of Working

Virtual
- Please mute unless talking
- The Chair will ensure you're included; raise your hand on Teams to come in
- Use the chat function to flag connection issues
- Keep cameras on for active discussion

- Talk – pause – talk
- Don't talk over people and let others contribute

Understand not everyone processes information and comes up with ideas in the same way

Use the breaks to reflect and recharge

If the fire alarm goes off, please exit the building and assemble at the evacuation point

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Task Force Process

*Timeline not to scale

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Engagement

What are the different routes of engagement?

- Charging Futures Forum Updates
- TCMF
- Podcasts
- Charging Futures Forum Events
- Task Force Consultation
- Mid Task Force Industry Webinar

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Ofgem Update

Harriet Harmon

Progress to Date

James Stone

The objective of this session is to provide:

- Summary of discussions/achievements so far
- High-level overview of the work undertaken during the pause
- Highlights of key external developments since Task Force meetings ceased

Achievements

Since Task Force Launch, members have:

1. Identified industry engagement opportunities and agreed expectations of members
2. Explored and defined the problem statement and agreed scope of work
3. Discussed background and rationale for previous methodology changes
4. Clarified the definition of TNUoS (what it was designed to reflect)
5. Agreed the underlying principles of TNUoS and what it should aim to achieve (objectives)
6. Identified and prioritised areas for review or specific defects within current charging arrangements

Building on the work of the Task Force

During the hiatus in Task Force meetings, the ESO have:

1. Further reviewed the defects identified by the Task Force - taking account of what work could feasibly be undertaken during the pause
2. Engaged with wider industry in terms of areas of review and work packages the ESO intended to take forward and assess
3. Received approval for Network Innovation Allowance (NIA) funding for consultancy support – with subsequent onboarding
4. Refined and agreed (jointly with Ofgem) the scope of the analytical assessment and key deliverables of the project
5. Managed the project through the analytical phase with the output to then be taken back to the Task Force to support further discussion

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Industry Developments

There have been some recent, notable developments that interact with the Task Force scope of work:

1. **CMP413**: ‘Rolling 10-year wider TNUoS generation tariffs’ - looks to aid predictability by obligating the ESO to publish and fix (within a permitted range) generation tariffs for a rolling 10-year duration
2. **Offshore Charging Sub-Group:** established in Feb 23 with the aim of providing input and developing charging methodology changes to support the ESO in creating a set of modifications to facilitate the HND/offshore coordination.
3. **CMP405: ‘**TNUoS Locational Demand Signals for Storage’ - 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, i.e. When Wind Generation is fully operating.

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Analytical Support

Frontier & LCP

The objective of this session is to provide:

- A high-level overview of the assessments undertaken so far, including; approach to the review, issues identified, initial analysis and conclusions, and potential solutions.

TNUoS Taskforce analytical support

Meeting with TNUoS Task Force

26th April 2023

Agenda

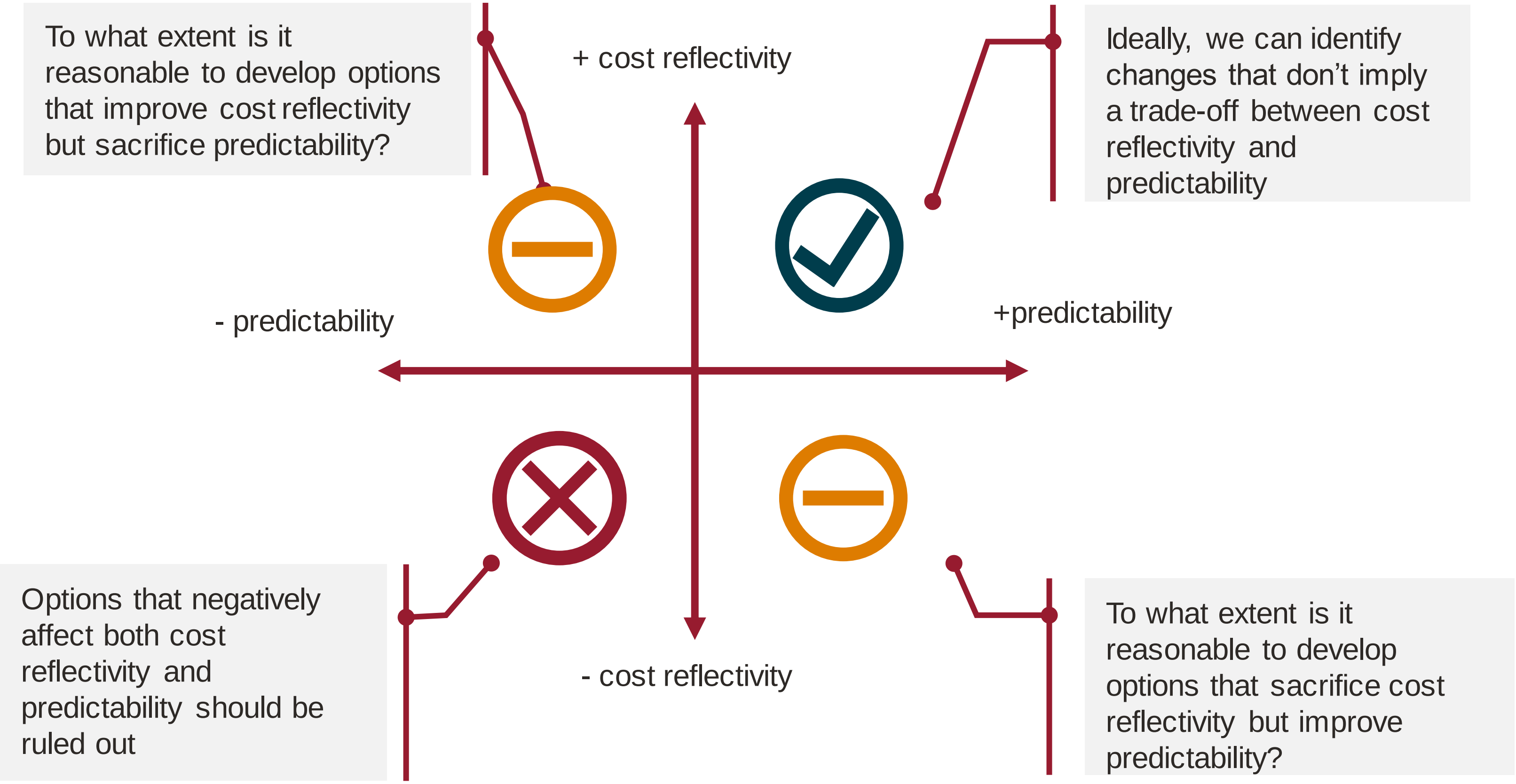
Agenda

Our review considers four areas identified by the ESO based on the earlier work from the Taskforce

Backgrounds	▪ Review appropriateness of current backgrounds.
Shared/not shared elements	▪ Review of the shared/not shared elements of the Wider tariff and whether they continue to be based on appropriate, cost-reflective assumptions.
Review data inputs	▪ Assess potential improvements of issues with the data inputs identified by ESO.
Reference node	▪ Describe the original rationale of the current reference node and test the impact of moving to a generation weighted reference node.

A key focus of this work consists of identifying improvements to cost reflectivity while also improving predictability for investors

While we will seek to identify options that improve cost reflectivity while also improving predictability, it may be that many options will imply a trade-off between the two, that we will need to understand.



Agenda

Our analysis suggests that updates to the current backgrounds could be appropriate

We first consider cost reflectivity…

- We assess the extent to which current backgrounds are representative of maximum network flows, and…
- …consider possible alternative backgrounds that are more closely aligned with maximum network flows.
- We consider the implications of this analysis for whether to apply a single background, two backgrounds (i.e. current approach), or additional backgrounds.

… and then predictability

- We assess the implications for tariff volatility of applying two backgrounds or a single background.
- Specifically, we compare the evolution of tariffs over the last five years when using two backgrounds against:
  - a Peak only; and
  - a Year-Round scenario.

- 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 would entail a small reduction in cost reflectivity, relative to two backgrounds. As an 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

- However, 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.

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

Cost reflectivity

In this analysis we assess the extent to which the current backgrounds are likely to represent the true cost driver (max flow) on each network element, and the extent to which alternatives may be more cost reflective

Methodology for obtaining the most representative backgrounds

1. We ran LCP's dispatch model for 2025 & 2035 to obtain load factors on assets for every hour of the year
2. Selected 96 periods (2 days per month, 4 hours per day) to cover a wide range of situations and ran all of these "backgrounds" through LCP's version of the transport model
3. Find the maximum flow across each circuit from all 96 backgrounds
4. Identify the backgrounds that give a 'good' representation of the most circuits (where 'good' is defined as 90% of the max flow)

	Current backgrounds			Most representative backgrounds			
	2025			2025		2035	
Technology	*Peak*	*Year-round*	*Combined*	*Round 1*	*Round 2*	*Round 1*	*Round 2*
Embedded gen	-	-		13%	13%	-15%	6%
Biomass	88%	27%		68%	68%	99%	100%
OCGT	88%	0%		0%	77%	0%	40%
CCGT	88%	27%		21%	95%	0%	94%
Hydro	88%	27%		64%	64%	52%	64%
Interconnectors	0%	100%		48%	59%	-93%	90%
Nuclear	88%	85%		100%	100%	100%	100%
Wind Offshore	0%	70%		87%	4%	71%	30%
Wind Onshore	0%	70%		81%	4%	62%	2%
Pump Storage	88%	50%		0%	58%	0%	0%
Demand	52,417	52,417		50,547	50,770	61,552	72,121
% represented	32%	33%	43%	59%	67%	72%	84%

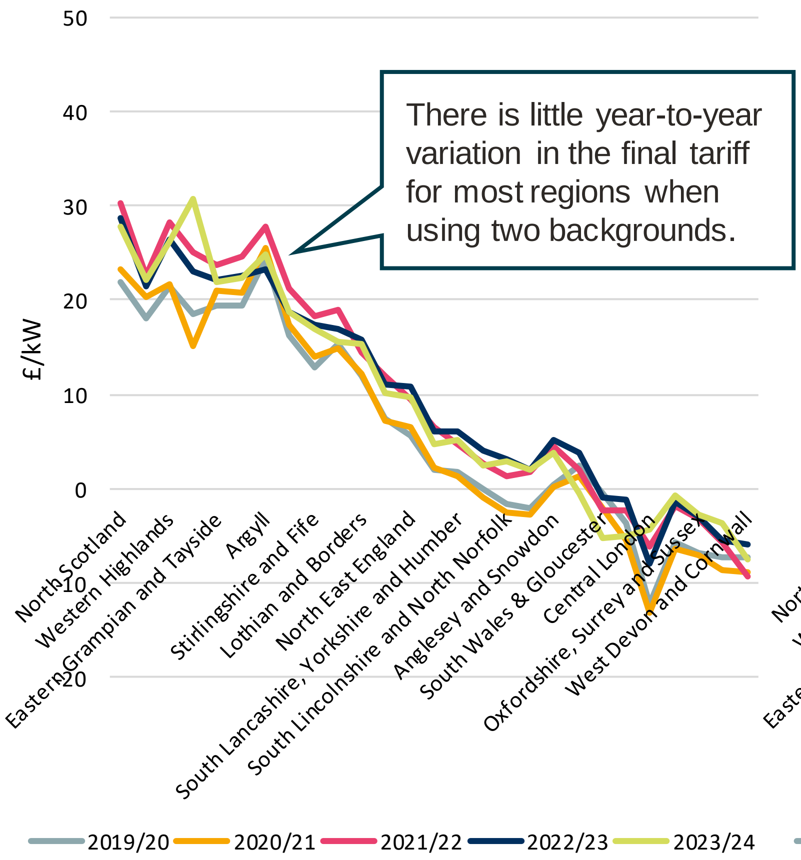
Current Peak and YR scenarios do not provide a very good representation for over half of the network.

Similar to YR

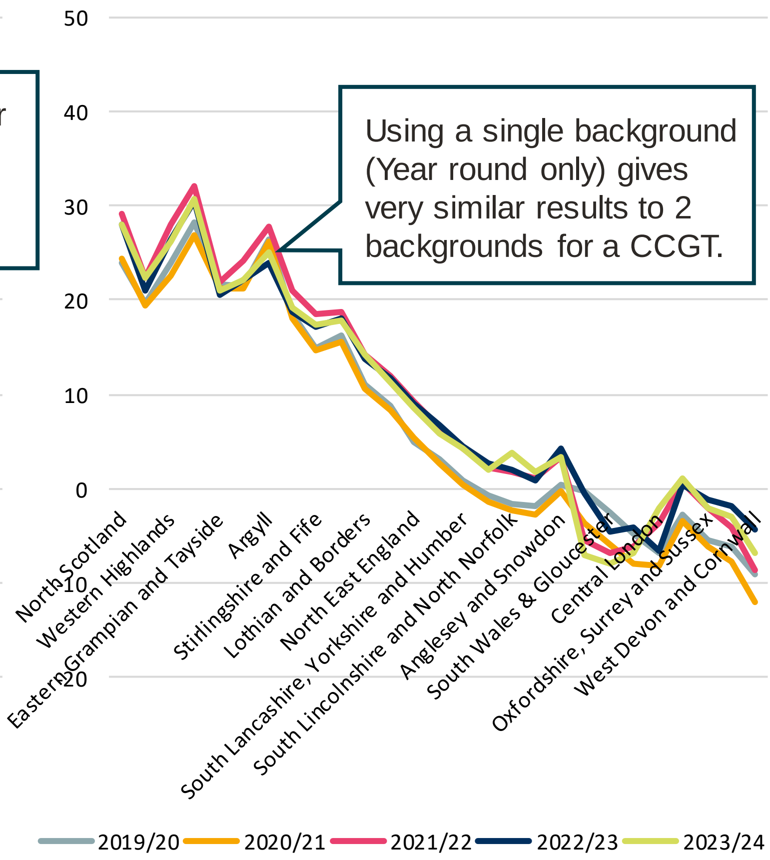
Similar to Peak

For a CCGT plant, volatility of charges only appears to be materially affected if applying a single peak scenario…

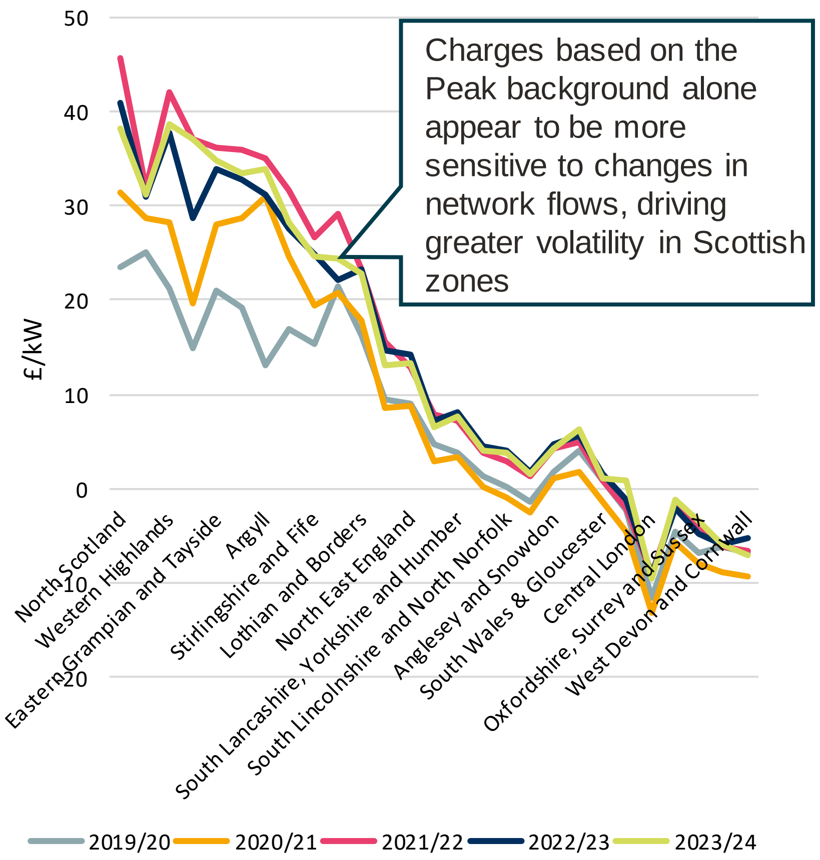
Wider tariff, CCGT – both



Wider tariff, CCGT – Year round only



Wider tariff, CCGT – peak only

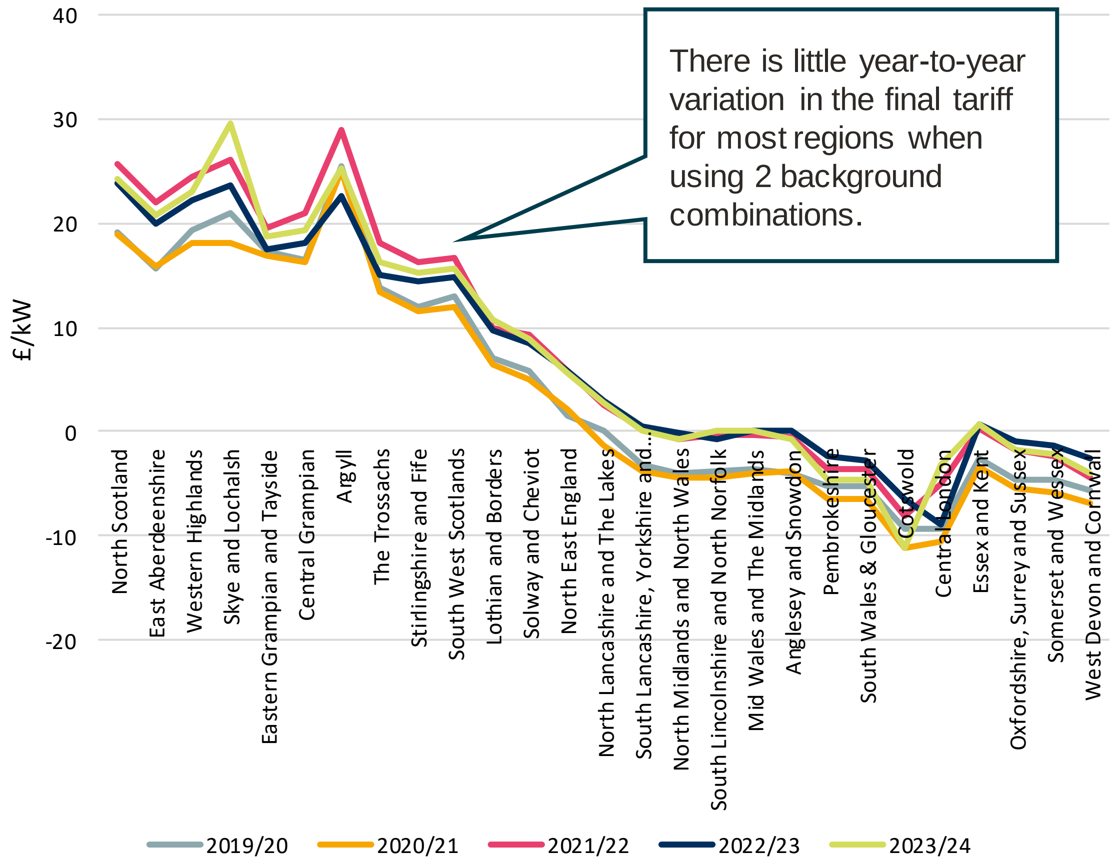


**Assuming a 70% annual load factor for CCGT plant*

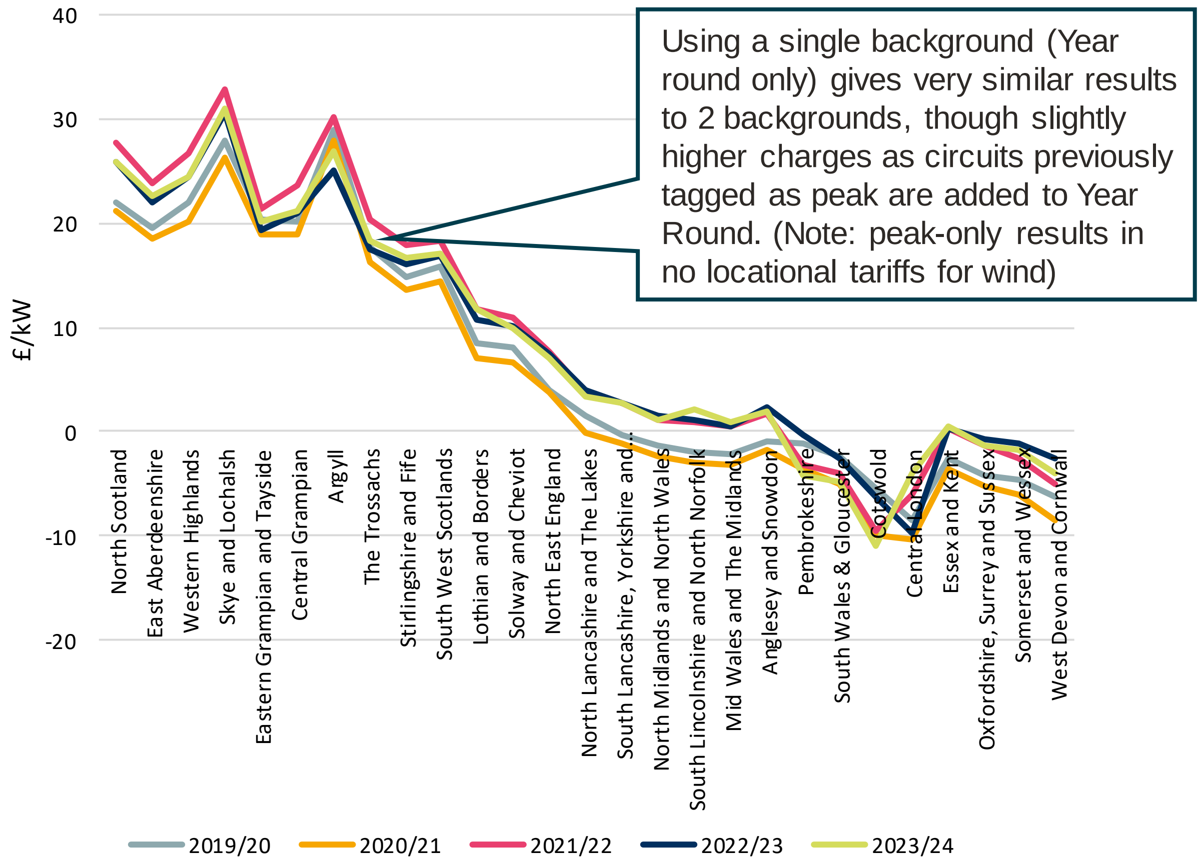
...for wind, we find limited impact on volatility from applying a single background, although there is an implication for the level of charges

Predictability

Wider tariff, wind – both



Wider tariff, wind – Year round only



Assuming a 40% annual load factor for wind plant

The five most representative backgrounds in 2025 and 2035

2025

Technology	Round 1	Round 2	Round 3	Round 4	Round 5
Year	2025	2025	2025	2025	2025
Month	1	2	9	9	12
Day	8	8	23	23	8
Hour	18	18	4	7	18
Embedded gen	13%	13%	5%	12%	11%
Biomass	68%	68%	3%	3%	68%
OCGT	0%	77%	0%	0%	0%
CCGT	21%	95%	0%	0%	83%
Hydro	64%	64%	0%	57%	64%
Interconnectors	48%	59%	-80%	0%	65%
Nuclear	100%	100%	100%	100%	100%
Wind Offshore	87%	4%	87%	88%	44%
Wind Onshore	81%	4%	77%	86%	9%
Pump Storage	0%	58%	-61%	-35%	0%

Demand	50,547	50,770	26,508	39,370	49,612

% represented	59%	67%	76%	83%	84%

2035

Technology	Round 1	Round 2	Round 3	Round 4	Round 5
Year	2035	2035	2035	2035	2035
Month	3	2	1	1	1
Day	8	8	8	23	8
Hour	18	18	13	7	18
Embedded gen	-15%	6%	-8%	15%	14%
Biomass	99%	100%	99%	99%	99%
OCGT	0%	40%	0%	1%	0%
CCGT	0%	94%	0%	90%	0%
Hydro	52%	64%	59%	41%	64%
Interconnectors	-93%	90%	-81%	81%	-12%
Nuclear	100%	100%	100%	100%	100%
Wind Offshore	71%	30%	75%	6%	45%
Wind Onshore	62%	2%	20%	18%	36%
Pump Storage	0%	0%	0%	100%	100%

Demand	61,552	72,121	56,608	58,690	62,075

% represented	72%	84%	88%	89%	90%

Agenda

Summary of approach and initial conclusions

Approach

We have carried out a conceptual review of how the sharing arrangements are currently applied to the Year Round charges. This has included reviewing Project TransmiT documents and analysis to understand the original justification for the current sharing factor calibration.

Initial conclusions

- From a conceptual perspective, the rationale for sharing still seems relevant under the current Year Round background, or any improved 'Year Round' background that intends to represent outcomes over a range of different scenarios that may occur.
- Therefore, while a discount remains appropriate in some circumstances, the sharing factors applied should only be considered as a representation of the concept and will not perfectly reflect the true extent of sharing.
- Key questions remain:
  - Sharing can only ever be an approximation, but the rationale for using the precise sharing function is not clear from historic documents i.e. how the current sharing factors were calibrated, and therefore it is unclear whether these could be improved upon;
  - In future, the sharing function has a smaller impact on charges as wind comes to dominate more and more zones, so sharing may become less relevant.

Next steps

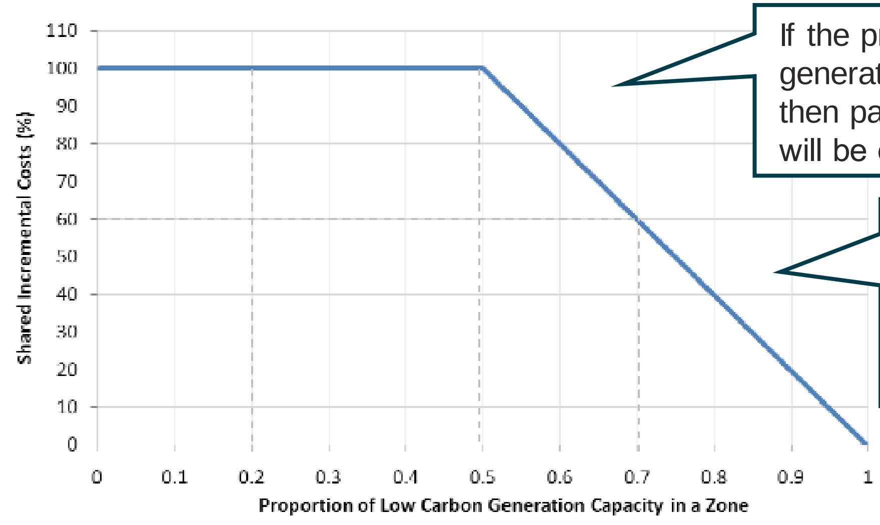
- We are in the process of examining FPN data to understand the extent to which "sharing" can currently be observed in some charging zones
- We can also potentially consider:
  - what the impact would be on charges if the BSFs were changed or removed entirely, to understand their materiality
  - the long-term implications of this assumption, and how materiality changes over time i.e. test impact on charges in 2035

The current arrangements provide a discount on charges based on the ability of different generators to share transmission capacity

The Year Round tariff is split into two elements: 'shared' and 'non-shared' based on a generators' ability to 'share' transmission capacity

- Conceptually, the ability of generators to 'share' transmission capacity is determined by the extent to which, prior to any redispatch actions by ESO, output by generators within a zone is positively or negatively correlated. For example: Wind plants are likely to be generating at the same time (i.e. when the wind blows) in a given location and so cannot share transmission capacity by utilising it at different times.
- The current methodology seeks to reflect this by providing a discount on the Year Round element of network charges based on the ability of generation assets within a zone to "share" transmission capacity
- The level of discount is determined by Boundary Sharing Factors which are a function of the share of low marginal cost capacity in a zone.

Calculation of Boundary Sharing Factors



If the proportion of low carbon generation in a zone exceeds 50%, then part of the Year Round tariff will be classed as 'non-shared'

The proportion of the Year Round tariff that is non-shared will increase as the percentage of low carbon generation increases

Classification of generation technologies

Carbon	Low Carbon
Coal	Wind
Gas	Hydro (ex. PS)
Biomass	Nuclear
Oil	Marine
Pumped Storage	Tidal
Interconnectors	

'Carbon' vs 'low carbon' classification is really about zero/low marginal cost vs positive marginal cost. Hence biomass is classified as carbon

Solar is not included in the technology list in the CUSC, but we assume it would be categorised as low carbon

The rationale for sharing is derived from the fact that an approach based on a limited set of backgrounds is a simplification of reality...

The key overarching aim is to develop charges based on peak flows

This is intrinsically linked to the use of the different backgrounds, and the extent to which these are representative of the full range/distribution of possible generation patterns that may occur

- In theory, N number of backgrounds could be applied to fully represent the range of scenarios in which maximum flows are achieved for each network element i.e. in the extreme a different background could be derived for each network element.
- In this example, charges could be derived as follows:
  - Incremental generation is added to each node against each background to estimate the MWkms triggered.
  - Incremental costs (MWkm*ExpC) would then be paid by generators according to their likelihood of generating in each background i.e. generator pays incremental cost at their node, multiplied by the load factor for the relevant background.

✓ **This approach would have a number of advantages, in particular:**

- There is no need to apply ALF in calculating charges, since load factors are specific to all scenarios in which plants generate
- There is no need to apply sharing factors, since the impact of a high concentration of low carbon generation would be reflected in the particular scenarios represented by each of the backgrounds for each network element

✗ **However, in practice this is not feasible / practical since:**

- This is a forward-looking exercise and therefore subject to significant uncertainty
- Practicality / time intensity of applying specific charges across a large number of backgrounds / scenarios

...and in this context there is a logic supporting its inclusion

The current Year Round background is intended to represent a wide range of possible scenarios which have different technology mixes, patterns of generation, load factors etc. It is only in this context that the sharing factors and discount (ALF) are potentially appropriate, and are intended to enhance how reflective the Year Round scenario is of a much broader set of scenarios

Under this approach:

- The charge is multiplied by ALF, as a simple proxy for the effect that a specific plant has on constraint costs and hence network investment.
- Sharing factors are used to calibrate when a discount based on ALF is appropriate.

ILLUSTRATIVE EXAMPLE - No use of sharing factors

A wind plant with an ALF of 30%, would face a single charge as follows:

Wider tariff = **ALF (30%)** × **Year Round** + **Generator residual**

i.e. without the use of sharing factors, the charges assume that the costs imposed on the network by a wind plant are proportional to its ALF. For zones with high wind penetration, this is likely to understate the true costs imposed on the system by the wind plant because periods of congestion are correlated with wind output.

ILLUSTRATIVE EXAMPLE – Impact of sharing factors

Zone with:
10GW wind
0GW thermal

- 100% low carbon generation, congestion (and hence investment case for network) driven entirely by wind
- Incremental 1MW of wind, due to its correlation with existing output, will trigger investment related to its full capacity (i.e. *no discount is appropriate*)

Zone with:
5GW wind
5GW thermal

- 50% low carbon generation, so assumption there is 'perfect' sharing, so congestion driven part by wind and part by thermal.
- Incremental 1MW of wind, only part of investment case for reinforcement (i.e. that related to correlated output of wind) on boundary (i.e. *discount is appropriate)*

- Therefore, a particular technology mix in a zone could imply 'sharing' and hence a discount is reasonable.
- Key driver of sharing relates to merit order, but merit order outcomes are set in the national market (not locally) such that the extent of sharing may differ locationally.

While sharing is not a perfect approach, there is a logic supporting its inclusion in the methodology.

Agenda

ESO has identified some potential concerns regarding the implications of certain data inputs for charge volatility and predictability

1 ALFs	▪ ALFs are calculated as a rolling 5 year average and so significant changes in the values are smoothed over time creating some stability year to year. However, in the context of rapidly changing load factors (due to technological advancements etc) it is considered that ALFs may need to be reviewed in terms of both the appropriateness of the calculation [i.e. ALF = max (HH, PFN)], as well as the 5-year frequency.
2 Charging bases	▪ The ESO demand charging base forecast process aims to ensure accurate recovery of revenue with the charging base forecast continually refined until final tariffs are published (each January). Considerable movements to charging bases have been witnessed in recent years with industry suggesting this element should be “locked down” in advance. There may be merit in reviewing the ESO processes and this option to lock down the forecast at an earlier stage.
3 Week-24 data	▪ All DNOs provide their “best view” of the likely nodal demand in the Week 24 forecast, however, the practice may not be consistent across the 14 regions and or DNOs. In addition, the forecast provided by the DNOs is based on net demand (not gross demand) which is inconsistent with SQSS. There could be alternatives to the DNO data to consider, for example use of network planning data such as the Electricity Ten Year Statement (ETYS) or the ESO Future Energy Scenarios (FES) which does not rely on DNO ‘forecasts’.
4 Demand forecasts	▪ There are inconsistencies between the method of forecast on demand charging bases (by zones and associated demand assumptions), and the DNO’s forecast of nodal demand that are used to set locational tariffs which may cause issues. The charging base forecast is based on a Monte-Carlo model, while the Week 24 data are provided by DNOs – with the former focussing on revenue recovery, while the latter focuses on transparency.
5 TO data	▪ The locational tariffs are dependent on a set of parameters which are reviewed every 5 years by Ofgem (during the RIIO Price Control period) – this refresh can cause some considerable near-term change to the tariffs between price control periods and volatility in TNUoS. ▪ In addition, there are some project-specific items that the ESO are not able to publish (e.g. cost of HVDC links) which reduces transparency to industry. (We note that these items are related to expansion factors and CMP 315/375 are dealing with this issue)

Beyond a potential change to the ALF calculation, we have not identified a strong case for change among the remaining issues

1 ALF

- Suggestion that faster adjustments to ALF may be more appropriate is not clearly supported by the available data. There may be some technology specific situations that merit further investigation e.g. declining LFs for thermal plants
- There may be some merit in using FPN to measure ALF instead of taking the higher of HH and FPN.
  - Moving to HH would not be appropriate because it reflects system balancing actions
  - Using FPN would capture the output before system curtailment (albeit with some forecast error), although there may be small incentive effects to consider.
- We propose to examine ALFs with and without this change.

2 Charging base

- Short term (<1 year) forecasting errors in charging base measures appear to have reduced following the move to gross charging, although some errors remain.
- Variations in charging base no longer affect residual charges
- Effect on locational charges is likely to be marginal and directional impact is unclear
  - Impact is through implied changes in network flows
- Short term demand forecast errors likely have limited impact on long term investment (key question is unpredictability of final charges over project life)

3 Week 24 data

- Given the absence of a fully prescriptive methodology for DNOs to follow there may be some inconsistencies in Week 24 forecasts between different DNOs
- This could be narrowed if more prescriptive guidance is issued.
- However, the scale of any possible improvement is unclear and untestable ex ante.
- Information regarding specific date and time of peak demand reduces potential for discrepancy.

4 Inconsistent Demand Data

- The different measures of demand serve different purposes:
  - ESO Triad demand forecast is required for determining the demand charging base, and hence relates to cost recovery.
  - Week 24 nodal data is used in the Transport Model as part of the backgrounds to assess peak flows.
- The key question relates to whether ACS demand is most appropriate for determining peak network flows. Demand in the backgrounds is being considered separately.

5 TO Data

- We understand this issue to primarily refer to the update of TO data in line with the regulatory cycle (5 years)
- Initial thoughts on options are essentially to introduce a lag between the revision of TO data and charges. This would trade off short term cost reflectivity improvements with greater certainty
- However, this overlaps to a degree with CMP315 and CMP375

Agenda

What is the reference node?

The reference node is a concept in the Transport model that determines how flows on the network are assumed to adjust to a marginal increase in generation at a location.

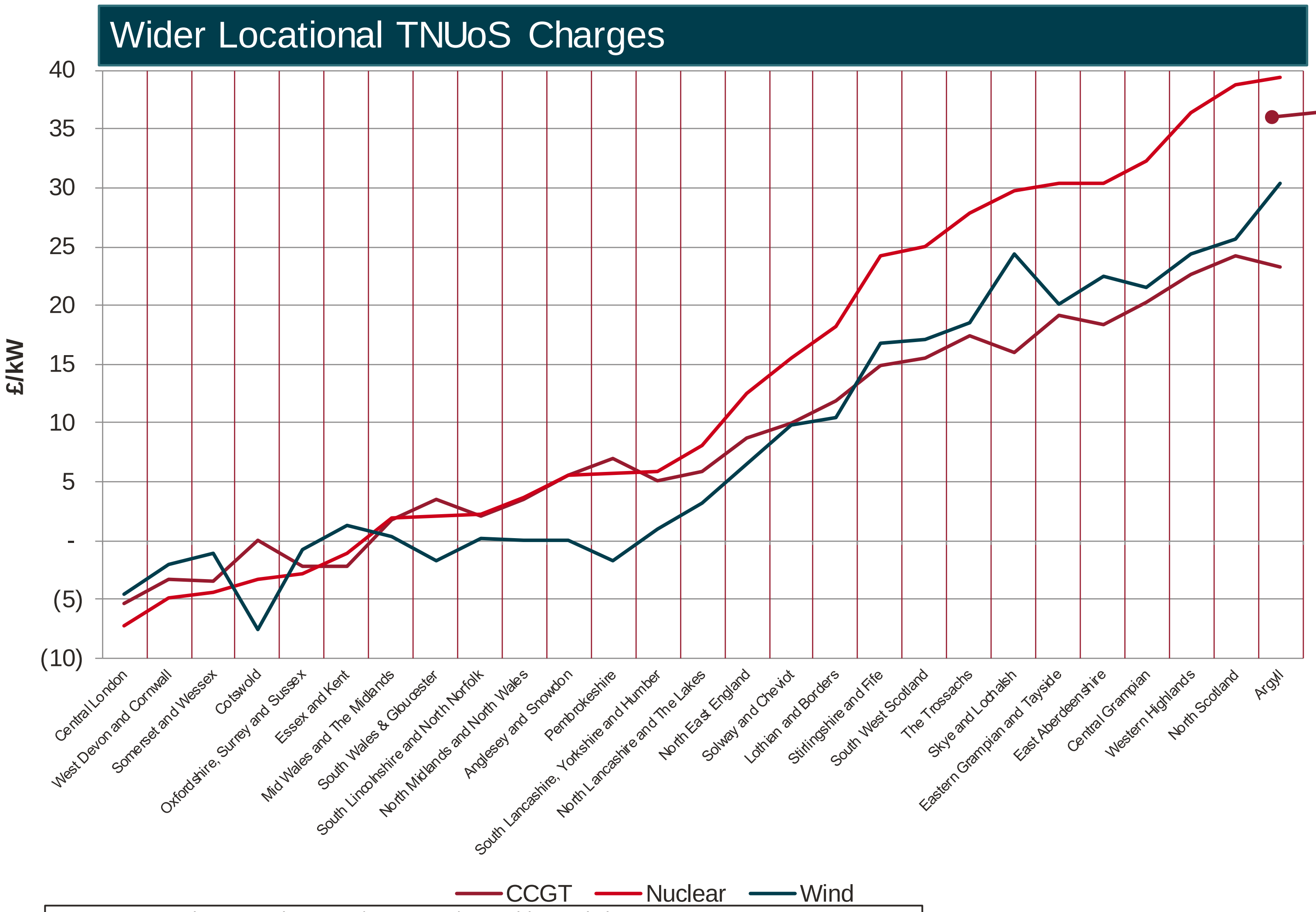
- The Transport Model contains a representative map of the GB transmission system with around 900 nodes
- Each node has *demand* and/or *generation capacity* that creates a ‘baseline’ system
- TNUoS charges are derived by adding generation capacity and measuring the impact on the network of revised system flows
- 1MW of generation capacity is added to a node. As the system must balance 1MW is also added to demand in the model
- The current reference node is a demand weighted distributed reference node.
  - This means that the 1MW increment to system demand is spread across all the demand nodes in the system in proportion to their contribution to total demand
  - It also means that the reference node is relatively “closer” to demand than generation, making average demand charges = 0, with positive recovery from generation

There are a number of potential issues to consider regarding the choice of reference node

Relative G/D cost recovery	■ The reference node determines the relative cost recovery between G and D. Therefore, could choose to move reference node if targeting a different relative split (though any split must be consistent with €2.50 cap*) ■ However, this can be more easily achieved through ex post adjustment to achieve €2.50 cap.
Impact of 'floored at zero'	■ The relative location of the reference node affects the absolute value of the locational charge and therefore the extent to which floored at zero is binding for users that face DTNUoS (i.e. floored at zero would have a smaller impact if there was greater recovery from demand)
Competition	■ Possible concerns about competition between different types of generation (TG, DG, BTMG) due to differences in cost recovery between G and D ■ Moving the reference node would not change the relative raw charges calculated for TG vs DG and BTMG at a particular location (i.e. incremental costs calculated in Transport Model for G and D are equal and opposite for each node). Differences arise due to other factors such as zoning, and ALF. ■ However, it would affect the extent to which floored at zero binds and thus the scale of the distortion it induces.
Impact of ALF	■ The difference in the ALF based discount on network charges, depending on location (they are larger if further from the reference node), may be perceived as distorting competition between technologies. ■ Moving the reference node would result in these discounts changing, and it is unclear whether this can be described as cost reflective

*Commission Regulation (EU) No 838/2010 restricts the annual average transmission charges paid by electricity generators in Great Britain to the range of €0/MWh to €2.50/MWh. This was introduced to try to provide a level playing field for competition between generation capacity in different EU states.

Impact of the reference node on the relative charges for high and low ALF technologies



Source: TNUoS Five-Year View 2021/22 to 2025/26 - Tables and Figures

The gap between high ALF (nuclear) and low ALF (e.g. onshore wind) is larger the further from the reference node.

This is because ALF is applied as a multiplier to the absolute value of the year round charge.

This means that although generation far from the average location of demand faces higher charges, low load factor plant in these locations receive a greater discount on charges relative to a high load factor plant, than an equivalent low load factor plant closer to the reference node.

There are two main options to consider – our initial view is that we do not see a strong argument for moving away from the current approach

Distributed Generation

- Assumes that additional generation always displaces other generation evenly
  - Formally this assumption is that new generation leads to retirement of existing generation rather than one new investment displaces an alternative new investment
- Zero average generation charges & +ve average demand charges
  - Low ALF generators receive no average discount
  - Reduced 'floored at zero' distortion to TG vs DG & BTMG because of higher average demand charges
- Possibly less stable than demand weighted and implies a different reference node for the peak and year round scenarios

Retain distributed demand

- Assumes that additional generation is always matched by additional demand at the average location of demand
  - Logic is that increasing demand is met by generation at a location
- Zero average demand charges & +ve average generation charges
  - Low ALF generators retain average discount
  - Current 'floored at zero' distortion to competition between TG vs DG & BTMG
- Possibly more stable than a generation weighted approach
  - Currently implies a single reference node for both peak and YR scenarios

While there is not a clear conceptual case for choosing one reference node over another, we plan to test the implications for charges of distributed generation and demand weighted reference nodes

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Charging Futures
Reforming electricity charging together

Break

Next session starts at 12:00

Feedback & Further Discussion

All

Forward Looking Plan

James Stone & Nicola White

Proposed timeline

Considerations

- Following feedback in terms of previous planned timelines, meeting efficiency, potential blockers etc a revised indicative plan has been drafted.

- It is proposed that:
  - Task Force meetings to continue going forward with monthly frequency – with fortnightly shorter meetings (check ins/actions updates) held virtually.
  - To revisit defects list in future meetings to identify further packages of work to be undertaken (in addition to areas & analysis already worked on during the pause).
  - Task Force report likely to be phased with initial analysis and options, as outlined today, being the 1st stage to deliver with further iteration at a later date.

Charging Futures

Forward Looking Plan

Activity	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23
Analytical support & Draft findings									
Task Force Meetings (Potential Topics)									
Mtg5 - Recap + Overview of consultancy support output (analytical assessment)	Mtg5								
Mtg6 - Deep dive assessment areas + Review final analysis & options etc + Identify Gaps (analysis) + Review Draft Consultancy Report		Mtg6							
Mtg7 - Further develop work on any gaps identified + Options Development + Consider further issue of improving predictability (identify analysis required)			Mtg7						
Mtg8 - Progress work on issue of improving predictability + Solution Development + Analysis to support + Agree Draft Report structure & initial content (begin draft)				Mtg8					
Mtg9 - Review & Action Draft Report Feedback + Agree final recommended solutions + Agree any actions					Mtg9				
Mtg10 - Finalise draft report structure & content + Agree consultation questions + Consultation webinar planning + Issue report for consultation						Mtg10			
Mtg11 - Consultation Response review & summary + Agree final actions to deliver report							Mtg11		
Mtg12 - Review of actions + Compile final report & deliver								Mtg12	
NIA Progress Report - Draft begins May-23 + Final report published Jul-23									
6-week Consultation period (TBC)									
Review & action responses / Issue Report to Ofgem									
NIA Completion Report - Draft begins Oct-23 + Final report published Dec-23									

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Proposed timeline

Considerations

The following dates have been considered to balance attendance for TCMF, CUSC Panel and holiday period:

- TF6(f2f) 24th May
  TF6(a)(v) 12th-16th June
- TF7(f2f) 26th/27th/28th June
  TF7(a)(v) 19th/20th/21th July
- TF8(f2f) 31st July/1st/2nd August
  TF8(a)(v) 14th-18th August
- TF9(f2f) 4th/5th/6th/8th September
  TF9(a)(v) 18th-22nd September

(f2f) face to face
(v) virtual
(a) actions check-in

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Thank you