# CUSC Code Administrator Consultation Response Proforma

## CMP324/5 Generation Zones – changes for RIIO-T2 and Rezoning – CMP324 expansion

Industry parties are invited to respond to this consultation expressing their views and supplying the rationale for those views, particularly in respect of any specific questions detailed below.

Please send your responses to cusc.team@nationalgrideso.com by **5pm** on **24 June 2020**. Please note that any responses received after the deadline or sent to a different email address may not receive due consideration by the Panel.

If you have any queries on the content of this consultation, please contact Joe Henry joseph.henry2@nationalgrideso.com or cusc.team@nationalgrideso.com.

| Respondent details | Please enter your details |
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### For reference the applicable CUSC objectives are:

a. *That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;*

b. *That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);*

c. *That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;*

d. *Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1 *; and*

e. *Promoting efficiency in the implementation and administration of the CUSC arrangements.*

**Objective (d) refers specifically to European Regulation 2009/714/EC. Reference to the Agency is to the Agency for the Cooperation of Energy Regulators (ACER).*

**Please express your views in the right-hand side of the table below, including your rationale.**

<table>
<tr><th colspan="3">Standard Code Administrator Consultation questions</th></tr>
<tr><td>1</td><td>Do you believe that the CMP324/5 Original solution, WACM1, WACM2 or WACM3 better facilitates the Applicable CUSC Objectives?</td><td>a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity<br><br>The DCLF ICRP model used to generate TNUoS charges is a model created many years ago, it has been incrementally amended via various industry mechanisms, over a period where the system characteristics have undergone considerable change. The GB electricity grid is complex, and therefore this model is inevitably an imperfect representation. It is a characteristic of the charging model that nodal costs vary significantly between each other and over time as a result of system usage shifts, changes in modelling assumptions, rezoning and TO planning choices.<br><br>The nodal volatility generated by the model does not affect all technologies or geographies equally, in particularly it adversely impacts North Scotland region (The SHETL area has twice the standard nodal deviation for year-round prices) as a result wind and hydro generation located there have greater price volatility risk with respect to charging, which adversely affects competition.<br><br>We have a specific concern regarding generation in the existing zone 1 In the transport model, the Caithness-Moray HVDC 800MW is 161km and has an expansion factor over 20 times higher than a 400kV OHL. We expect that increasing the number of zones, changes to charging (embedded generators facing TNUoS), historic reinforcement planning decisions (the HVDC link) and other model assumptions (treatment of HVDC convertor costs differently to substations) will lead to high specific nodal costs, making the new generation, that the HVDC link was intended to facilitate, unviable. It will also, increase costs for existing projects (which did not need the link) and result in a stranded asset for the TO, which given its approval by Ofgem, we would expect costs to fall to consumers. This is one example but with increasing numbers of nodes this situation could be repeated elsewhere.</td></tr>
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As the GB electricity system transitions to meet Net Zero there must be a significant increase in electricity demand to decarbonise, heat, transport and industry. The location and uptake of new demand plus demand side response will become increasingly important. Different zones and locational signals for demand and generation does not facilitate a level playing field between the solutions and is therefore detrimental to competition.

For these reasons we believe the proposer's Original solution is best with respect to this objective.

b) *That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);*

The TNUoS charging model attempts to allocate *some* of the costs incurred by the transmission licensees. We agree with the principle and use of locational charging, however there is a danger in assuming that moving toward greater granularity automatically results in greater cost reflectivity, and thereby reaching the conclusion that individual nodal prices, or as many zones as the ESO could practically administer, would be the ideal cost reflective outcome.

Modelling cost reflectivity of such a complicated system is challenging, highly dependent on the methodology adopted and the assumptions used. There are many other valid justifiable approaches that could be taken which would lead to a wide spread of potential results for a particular node - the margin of error in the existing approach and spread of justifiable nodal costs from other approaches is very high. Modelling that yields high levels of uncertainty should not be used to high levels of precision – increasing the number of zones and moving to more granular nodal pricing increases the chance of amplifying errors in individual nodes, and so is likely to *hinder* cost reflectivity.

Here are some example assumptions that can have a big impact the outcome of nodal prices:

**Boundary sharing methodology** – the current model makes assumptions by simplifying the flow of energy to a notional centre of demand and creating system boundaries. Boundary

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| | | sharing occurs where there is flexible generation behind a boundary, but there is no modelled sharing if generation is only intermittent. This does not match reality – some intermittent generation is largely out of phase (wind/solar). In addition, a significant portion of sharing can be made even if there is only one type of intermittent generation (for example wind is not on full power for the majority of the time, wind does not blow uniformly across Britain, and a small portion of the fleet will always be unavailable).<br><br>**Constraints strategy –** The model assumes the transmission system will be built to full capacity (plus 1.8x security factor). In reality systems are increasingly designed with a lower capacity and a constraint management strategy as this is a lower cost design option (see for example the CBA work completed in Ofgem's latest Shetland consultation). The model does not reflect this lower cost reality.<br><br>**Substations:** the majority of costs that a conventional generator connecting in the south triggers can relate to substation upgrades not circuit upgrades – these costs can be large, but are socialised. Generator costs in Scotland however are likely to trigger distance related costs which are not socialised. Only socialising one set of costs that certain geographic locations and technologies are more prone to benefit from is distortive.<br><br>**HVDC**: The current treatment of convertors being included in HVDC expansion factors is inconsistent with the treatment of substation costs – they should be socialised as substation costs are.<br><br>**Planning and expansion constants:** how TOs solve constraints is to an extent a choice – it may be costlier, but easier and quicker to consent an HVDC link than an overhead line, and the regulated return model may not always be the most robust incentive structure in these circumstances. These decisions are outside the generators' control, but could have significant impact on the likelihood of affordable connections being made now or in years to come. Even if future north/south reinforcements were made using significantly cheaper solutions, the historic choices have a large impact on charges – this is counter to the *long run marginal* approach that is trying to be reached.<br><br>This can framed as a wider issue with the modelling approach, if 400kV overhead lines are now difficult for TOs to build across the country, it doesn't matter where new generation is located, the expansion factor of the most likely new circuit |

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| | | design solutions should be used, not the existing historical infrastructure if a long run marginal cost is to be derived.<br><br>**Net demand:** The model uses net demand not gross demand when pro-rating increases in demand when a MW of generation is added to a node to calculate its costs – this is distortive in zones that have high levels of embedded generation.<br><br>The examples above are only some of assumptions that can have a large impact on the nodal cost generated by the model, there are many more. The relevance to CMP324/5 is that there is a lot of potential noise and distortion in individual nodes and the model generally, this will to some extent be dampened by averaging the nodal costs across wider generation zones, so it is our belief that the Original solution is more cost reflective.<br><br>c) *That, so far as is consistent with sub-paragraphs (a) and (b), the use of system charging methodology, as far as is reasonably practicable, properly takes account of the developments in transmission licensees' transmission businesses;*<br><br>The specific issues highlighted by the Caithness-Moray HVDC link in response to objective a) poses a significant general risk to TOs developing their business. If due to planning (or whatever other reason) newer solutions are much costlier, this can result in suboptimal development of the transmission system. If generators follow the signal sent by the model and apply to connect in areas with low cost nodes due to existing cheap 400kV OHL infrastructure, reinforcements will need to be planned, if these are newer and more expensive solutions, the charges will increase significantly, and the generators may no longer see the benefit of connection in that location. There is a risk that most expensive places to connect generally become wherever the most recent reinforcements are made – the Original solution dampens this affect and reduces the risk of stranded assets so is beneficial to this objective.<br><br>d) *Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency. These are defined within the National Grid Electricity Transmission plc Licence under Standard Condition C10, paragraph 1 *; and*<br><br>*"(14) A proper system of long-term locational signals is necessary, based on the principle that the level of the network access charges should reflect the balance between generation and consumption of the region* |

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| | | *concerned, on the basis of a differentiation of the network access charges on producers and/or consumers.*"<br><br>We believe the Original solution improves compliance with clause 14 (above) in aligning demand and generation charging regions, the balance between the generation and consumption of the region concerned can be better reflected in network access charges. It also provides *long-term* locational signals, instead of the current medium-term signal resulting from frequent rezoning.<br><br>*e) Promoting efficiency in the implementation and administration of the CUSC arrangements.*<br><br>This Original solution will simplify the CUSC and the TNUoS charging model. This should reduce administration and forecasting costs and complexity for the ESO and the generators. |
| 2 | Do you support the proposed implementation approach? | Yes |
| 3 | Do you have any other comments? | **Complexity**: The Original solution reduces complexity of the the charging regime, this will have an incremental reduction in industry costs across many parties, lowering overall system costs.<br><br>**Remote Islands:** We have concerns that if remote island connections were to become part of the MITS they would significantly distort cost reflectivity (in zone 1), with generators in North Scotland providing a large subsidy for Island generators' connections. We do not believe this is cost reflective or fair from a competition perspective. We believe the Remote Island connections should be considered local circuits. However, if they are in future included in wider TNUoS charging, it is important that each island group forms a different zone as the costs are easy to separate/identify and vary significantly between Island groups: one Island link should not subsidise or increase the costs of the others.<br><br>**Point of connection to Transmission System**: We note that in the zonal mapping, some MITs substation nodes have more than one zone associated with them. For example, Swansea North has both zone 6 and zone |

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| | | 10 substation mapping. This does not appear to be logical – it is the geographic location of the point of connection to the transmission system that is relevant to generation TNUoS charging, not the the geographic location of the generator.<br><br>It is simpler and more cost reflective if all generators connecting into a transmission network substation receive the same locational signal – that of the zone the substation is in. |