CUSC Modification Proposal Form

CMP379: Determining TNUoS demand zones for transmission-connected demand at sites with multiple Distribution Network Operators (DNOs)

Overview: This modification has been raised to update Section 14 of the CUSC to clarify how TNUoS demand zones and therefore TNUoS demand tariffs and charges should be determined for transmission-connected demand users who connect at the boundaries of multiple DNO areas.

Modification process & timetable

1. **Proposal Form** 09 September 2021
2. **Workgroup Consultation** 21 January 2022 – 11 February 2022
3. **Workgroup Report** 17 March 2022
4. **Code Administrator Consultation** 30 March 2022 – 22 April 2022
5. **Draft Final Modification Report** 19 May 2022
6. **Final Modification Report** 9 June 2022
7. **Implementation** 1 April 2023

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

This modification is expected to have a: Medium impact

This proposal will have a medium impact on Generators, transmission-connected demand users, Suppliers and National Grid Electricity System Operator.

Proposer's recommendation	Standard Governance Modification with assessment by a Workgroup

of governance route		
Who can I talk to about the change?	**Proposer:** James Stone James.Stone@nationalgrideso.com 07971 002704	**Code Administrator Contact:** Paul Mullen Paul.j.mullen@nationalgrideso.com 07794537028

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What is the issue?

Paragraph 14.14.5 ix.) of the CUSC states that "The number of demand zones has been determined as 14, corresponding to the 14 GSP groups" with 14.15.38 then stating that "Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes." The current wording of the CUSC allows for some level of flexibility in terms of how these demand zones can be used for tariff setting purposes.

At present, the 14 Transmission Network Use of System (TNUoS) demand zones are aligned with the 14 Distribution Network Operator (DNO) demand zones. Demand users pay TNUoS tariffs and charges, depending on the demand zones they fall within. For a distribution-connected user the demand zone is determined as the relevant DNO zone where the user is located. For a transmission-connected demand user, typically the geographic DNO zone determines that user's demand zone. **However, if the transmission-connected user is connected to a transmission substation which also feeds multiple DNOs via its local GSP (Grid Supply Point), which therefore spans multiple DNO zones, the site is essentially located at the "boundary point" between those DNO areas. Although the current wording within the CUSC does provides a level of flexibility, under these circumstances it is not explicitly clear within the CUSC charging methodologies which demand zone this user should be allocated to.**

Why change?

The latest Transmission Entry Capacity (TEC)[1] register shows that during the 2022/23 charging year several transmission-connected users (primarily energy storage systems) are expected to connect to the National Electricity Transmission System (NETS) located at a boundary point between multiple DNO areas. At present the CUSC charging methodologies do not clearly set out how the TNUoS demand zone and therefore the TNUoS demand tariffs should be determined for such a connection.

This modification seeks to update Section 14 of the CUSC to provide clarity on how TNUoS demand zones and therefore TNUoS demand tariffs should be determined for those transmission-connected demand users who connect at the boundaries of multiple DNOS. This will allow NGESO to provide clarity on how such connections will be treated and reflect them in the tariff setting and invoicing process and will also provide clarity and aid users in their understanding of network charges.

What is the Proposer's solution?

It is proposed that where a transmission site has a local GSP which connects to and feeds multiple DNO networks, the DNO with the highest local net demand MW value at that site (determined by the DNO 'week 24' demand forecast data used within the transport model) will be classed as the "predominant DNO". Subsequently, if a transmission-connected demand user is then connected to this transmission site, it will be assigned (for TNUoS tariff and invoicing purposes) the demand zone associated with the "predominant DNO" at the site. It should be noted that this demand zone may change on an annual basis given that the "predominant DNO" is determined by local demand forecast data which may change between charging years.

TNUoS locational tariffs are derived using various data sets including the TEC register published by NGESO as well as nodal demand forecast data from the Distribution Network

[1] ESO Data Portal: Transmission Entry Capacity (TEC) Register - Dataset| National Grid Electricity System Operator (nationalgrideso.com)

Operators. This data set is known as 'week 24' data and is provided by the DNOs and transmission-connected demand users to NGESO, by calendar week 24/28, under an already established process as part of Grid Code requirements. For any site where multiple DNOs connect, the relevant DNOs submit their 'week 24' nodal demand forecast, with the combined value then being the total GSP demand at the site. It is proposed that where a transmission site has a local GSP which connects to and feeds multiple DNO networks, those nodal demand MW values within this data are to be used to identify the highest DNO local demand at that site.

TNUoS demand tariffs are calculated by means of a weighted average of all demand sites nodal costs within the same demand zone, using the 'week 24' nodal demand MW values to determine the weighting. This means that clarifying the use of a "predominant DNO" to determine which zone transmission-connected demand users at boundary points belong to, will ensure that their demand values (in the event that the Generators do indeed take demand at a triad period) can be properly accounted for when calculating and applying zonal tariffs.

It should be noted that at the April 2021 Transmission Charging Methodology Forum (TCMF), alternative solutions to the defect detailed within this modification proposal were also discussed with industry stakeholders, for example, aligning the transmission-connected demand user to a demand zone by its geographic DNO location. However, the proposer considers this alternative when assessed against the original solution would not be practical to implement for those connected at a boundary point. The identification of a geographic DNO location for a transmission-connected user may be overly complex as the Transmission Owner (TO) and DNO can have assets at the very same location, and usually share the infrastructure (cable trenches etc). In addition, the geographic boundaries can "flex" over time depending on DNOs transmission-connection/disconnection activities.

Draft legal text

Changes to Section 14 of the CUSC as follows (the changes are shown in red text):

14.15.38 Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes.

14.15.39 Where a directly connected transmission site has a local GSP which connects to and feeds multiple DNOs, the DNO with the highest local demand MW value at that site is classed as the "predominant DNO". Subsequently, if a transmission-connected demand user is connected to this transmission site, it will be assigned the demand zone associated with the "predominant DNO" at the site.

What is the impact of this change?

Proposer's assessment against CUSC Charging Objectives	
Relevant Objective	**Identified impact**
(a) That compliance with the use of system charging methodology facilitates effective competition in the generation and supply of electricity and (so far as is consistent therewith) facilitates competition in the sale, distribution and purchase of electricity;	**Neutral**
(b) That compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable, the costs (excluding any payments between transmission licensees which are made under and accordance with the STC) incurred by transmission licensees in their transmission businesses and which are compatible with standard licence condition C26 requirements of a connect and manage connection);	**Neutral**
(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;	**Neutral**
(d) Compliance with the Electricity Regulation and any relevant legally binding decision of the European Commission and/or the Agency *; and	**Neutral**
(e) Promoting efficiency in the implementation and administration of the system charging methodology.	**Positive** Updates Section 14 of the CUSC by clarifying how TNUoS demand zones and therefore TNUoS demand tariffs should be determined for those transmission-connected demand users who connect at the boundaries of multiple DNO areas. This will provide clarity on how TNUoS tariffs for such users are calculated and will ensure consistent understanding of the charging methodology for all parties involved.

*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).

Proposer's assessment of the impact of the modification on the stakeholder / consumer benefit categories	
Stakeholder / consumer benefit categories	**Identified impact**
Improved safety and reliability of the system	**Neutral**
Lower bills than would otherwise be the case	**Neutral**
Benefits for society as a whole	**Neutral**
Reduced environmental damage	**Neutral**
Improved quality of service	**Neutral**

When will this change take place?

Implementation date
This modification proposal should be implemented on the 1 April 2023.

Date decision required by
A decision is required by 31 December 2022 as this will allow NGESO to adopt the methodology detailed within this modification proposal when determining the relevant demand zone and therefore TNUoS tariffs and charges for transmission-connected demand users located at the "boundary point" between multiple DNO areas from the 2023/24 charging year (i.e. from 1 April 2023).

Implementation approach
The TEC register shows that there are a small number of transmission projects (Generators) expected to connect (located at boundary points between multiple DNOs) during the 2022/23 charging year. Initial analysis performed by NGESO suggests the materiality, in terms of potential tariff difference, is within a range of £1.8/kW to £2.8/kW at each of the sites. The aggregated demand charge variation (due to difference in zones) for these projects in 2022/23, assuming they were to take full demand over the triad period, will be <£1m and therefore relatively small in the context of an overall total of £20m (including both locational and residual demand charges for transmission-connected sites) for these users. At present there are no demand only users directly connected at transmission, but should this happen the connectee and their Supplier would see similar levels of charge variations due to difference in demand zones. Taking this materiality into

account, and given that the CUSC isn't currently explicit with regards to how these connections should be treated, the Proposer considers it prudent to issue charging guidance to ensure industry have a clear understanding of the approach to be used for the 2022/23 charging year. The detail of this will be communicated to industry (via the TCMF) prior to the charging guidance being published on the NGESO website around the same time as the issuing of Draft 2022/23 TNUoS Tariffs in November 2021. Following which the solution created by this modification proposal would then be codified and implemented within the CUSC from 1 April 2023

Proposer's justification for governance route

Governance route: Standard Governance modification with assessment by a Workgroup

This does not meet the Self-Governance Criteria as this will materially impact TNUoS tariffs for those transmission-connected demand users located at boundary points between multiple DNO areas. Initial analysis in terms of the aggregated demand charge variation (due to difference in zones) for projects expected in 2022/23, assuming they were to take full demand over the Triad[2] period, will be <£1m.

The Proposer has discussed this topic at the April 2021 TCMF, and the governance route was chosen following feedback from industry stakeholders received at the meeting which suggested industry would welcome further discussion around the solution and possible alternatives.

Interactions

☐Grid Code	☐BSC	☐STC	☐SQSS
☐European Network Codes	☐ EBR Article 18 T&Cs[3]	☐Other modifications	☐Other

Not applicable

Acronyms, key terms and reference material

Acronym / key term	Meaning
CUSC	Connection and Use of System Code
DNO	Distribution Network Operator
GSP	Grid Supply Point
DNO	Distribution Network Operator
MW	Mega Watts
NETS	National Electricity Transmission System
NGESO	National Grid Electricity System Operator
TO	Transmission Owner
TEC	Transmission Entry Capacity
TNUoS	Transmission Network Use of System

[2] Triads are the three half-hour settlement periods with highest system demand. NGESO use them to determine charges for demand customers with half-hour metering

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

Reference material

- April 2021 TCMF slides: “TNUoS tariff for directly-connected demand users at site with multiple DNOs”

https://www.nationalgrideso.com/document/189941/download

- CMP379 indicative aggregated demand charge variation analysis for the 2022/23 charging year:

				Total (£k)	Total (£k)
				891	20736
Project	Connection Site	Plant Type	Assumed Triad Demand (MW)	ChargeDelta (£k)	total min net demand charge (£k)
Project 1	Axminster	Energy Storage System	49.9	140	2937
Project 2	Axminster	Energy Storage System	49.9	140	2937
Project 3	Iron Acton	Energy Storage System; PV Array (	120	273	6475
Project 4	Iron Acton	Gas Reciprocating	0	0	0
Project 5	Laleham 275kV	Energy Storage System	49.9	104	2833
Project 6	Melksham 400kV	Energy Storage System; PV Array (	49.9	140	2937
Project 7	Walpole 400kV	Energy Storage System	49.9	93	2616

					* based on 2021/22 final tariffs			
Site	DNO1	DNO2	DZone1	DZone2	DTariff1 (£/kW)	DTariff2 (£/kW)	TariffDelta (£/kW)	MinDTariff (£/kW)
Axminster	SEP	WPD	13	14	58.8652	61.6768	2.811593	58.865203
Iron Acton	WPDSW	WPDWM	10	8	56.2368	53.96	2.276836	53.959972
Laleham 275kV	SEP	SPN	13	11	58.8652	56.7721	2.0931	56.772103
Melksham 400kV	SEP	WPD	13	14	58.8652	61.6768	2.811593	58.865203
Walpole 400kV	EME	EPN	7	9	52.4282	54.2839	1.855784	52.428151