CUSC Modification Proposal Form

CMP423: Generation Weighted Reference Node

Overview: Reference Node: generation weighted instead of demand weighted

Modification process & timetable

1. **Proposal Form** 12 October 2023
2. **Workgroup Consultation** 02 July 2024 – 23 July 2024
3. **Workgroup Report** 21 November 2024
4. **Code Administrator Consultation** 02 December 2024 – 23 December 2024
5. **Draft Final Modification Report** 23 January 2025
6. **Final Modification Report** 12 February 2025
7. **Implementation** 01 April 2026

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: High Impact

G:D spilt may remain the same

Potential impact on generation charges

- Reduce scale and need for generator adjustment credit
- Reduce total collected from generation Wider locational towards £zero (currently large £positive collection)

Potential impact on demand charges

- Reduce the value of unavoidable Demand Residual charges
- Demand charges weighted more towards Wider locational charge

Proposer's recommendation of governance route	Standard Governance modification with assessment by a Workgroup	
Who can I talk to about the change?	**Proposer:** John Tindal John.tindal@sse.com 01738 341835	**Code Administrator Contact:** Ren Walker Lurrentia.Walker@nationalgrideso.com 07976 940 855

Contents

What is the issue?

The relevant defect identified by this proposal is that the TNUoS Transport model currently calculates incremental flows by bringing total generation and demand into balance by pro-rata increasing all demand using a "demand weighted reference node". For the reasons described in more detail below, this approach of using a demand weighted Reference Node is an issue because it is not cost reflective. It does not appropriately reflect how the system would respond to changes in user decisions and it distorts the relative locational price signals produced by the charging methodology.

The current demand weighted reference node also creates an issue for effective competition. This is because the existing methodology is expected to result in collecting an increasing total TNUoS cost from generation wider locational charges, which would further worsen the competitive disadvantage of GB generators compared with generators in other markets.

This modification proposes to rectify this defect by switching from a demand weighted Reference Node to a generation weighted reference node instead.

Why change?

The CUSC describes a relevant key principle of TNUoS charging as to reflect incremental cost i.e. the change in system cost caused by a network user from the decisions that user makes:

> "*The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy*."[1] (CUSC 14.14.6, emphasis added)

In order to reflect a correct incremental cost, it is necessary for the TNUoS charging methodology to appropriately model what resulting impact on the system would be caused by a user decision. For example, if a generator were to increase, or reduce generation capacity at a particular location, then: how would the rest of the system be likely to react in response to that decision and what corresponding incremental change in cost of network would that cause ?

The TNUoS Transport and Tarif model calculates the impact of such decisions in terms of incremental changes in MWkm power flows which may be either positive, or negative, contributing to higher, or lower charges respectively. The model does this by adding 1MW of generation at each node in turn, and applies adjustments to ensure that total generation and demand remain equal and measuring the resulting change in MWkm.

The issue this modification addresses is whether the pro-rata adjustment to bring generation and demand into balance should be carried out by the current approach of a pro-rata increase in demand, or a pro-rata reduction in generation.

Specific issues a CUSC Workgroup could consider include:

- Implications for the network sharing calculation in Transport and Tariff model
- Review potential locations for new generation such as via the TEC Register, seabed leasing, or other planning sources
- Assess the impact on tariffs that may arise from changes in the way circuits may be placed into either Peak Security and Year Round buckets

[1] CUSC - SECTION 1 (nationalgrideso.com)

What is the proposer's solution?

Before Project TransmiT, the choice of Reference Node did not change either the magnitude, or relative locational signals faced by different users because all users paid their locational tariff and Residual tariff on the same charging base, so it was not a material issue of concern.

However, after Project TransmiT and within the current methodology, the choice of either generation, or demand weighted reference node does now matter, because it would change both the magnitude of charges, as well as the relative locational signals paid by different parties. This is because different generators pay different elements of TNUoS charge, so changes in the value of tariff elements will impact different generators differently. For example, conventional generators pay the Peak Security tariff, while intermittent generators do not, all generators pay the Year Round Shared tariff by their own different station specific ALF, and conventional carbon generators have their ALF applied to their Year Round Not-Shared tariff, while other generators pay this at 100% of TEC.

The choice of Reference Node now also affects both the absolute and relative charges paid by demand customers. This has arisen since the Demand Residual is now applied to a different charging base from the locational demand charges. If demand charges were to be further changed to apply Peak Security and Year Round charges to different charging bases, then changing the reference node would further impact the magnitude and relative price signals paid by different demand users.

Switching to a generation weighted Reference Node would be better than the baseline in a number of ways, including those described below:

1) **Better cost reflectivity: Charges would better reflect incremental transmission system cost/benefit that is caused by a user's decisions.**

In practice, generation scales to meet demand, demand does not scale to meet generation. This principle of scaling generation to meet demand applies in the reality of operating the energy system, and also applies in the way the ESO Network Options Assessment (NOA) process and the Security and Quality of Supply Standards (SQSS) operate.

Generation charges: Generation weighted Reference Node is more cost reflective for generation charges

In practice, incremental increase (or decrease) in generation at one location will tend to cause a corresponding offsetting decrease (or increase) in generation at another location. It will not tend to cause changes in demand.

This is demonstrated in a number of practical ways, such as the way government sets targets for generation to meet demand, where the relevant question is where that target generation capacity will be located. This is demonstrated in auctions, such as the Contracts for Difference auction with budget caps where generators compete with each other and one generator winning a contract would tend to displace a different generator who did not win a contract. Similarly, for the Capacity Mechanism, generators also compete with each other to deliver a target required capacity, whereby one generator winning a contract will tend to displace a different generator that did not, and if a generator closes, then more generation capacity needs to be procured through a future auction to replace it.

This principle of generation tending to balance with other generation applies to both generator investment and closure decisions:

- **Impact of an <u>increase</u> in generation best reflected by a corresponding decrease in generation elsewhere:** Reductions in existing generation can only take place in locations where there is already existing generation that can close. Any corresponding reduction in hypothetical alternative generation, would also be best reflected by a weighted average of existing generation, because alternative new generation would be more likely to be weighted towards locations where there is already generation, not weighted towards locations where there is already demand.

- **Impact of a <u>reduction</u> in generation best reflected by a corresponding increase in generation elsewhere:** For the purpose of providing a risk weighted average, corresponding increases in generation should take place in locations where there is already generation. This is because additional generation is more likely to occur at places where there is already generation due to other limiting factors, such as: where there is access to gas grid, cooling, brown field sites, planning consents, wind resource, seabed availability. By contrast, it is not appropriate for corresponding increases in generation to be weighted towards areas dominated by demand, such as London city centre.

Demand charges: Generation weighted Reference Node is more cost reflective for demand

Increases (or reductions) in demand will also tend to be met with corresponding increases (or reductions) in generation, not by offsetting changes in demand elsewhere. This can also be demonstrated in practice by government targets of generation required to meet changes in expected demand, as well as scheme targets to procure appropriate generation capacities within the CfD and Capacity Mechanism to meet any changes in the expected level of demand.

By contrast, the current demand weighted Reference Node does not reflect reality, so is not cost reflective of the impact of demand decisions on incremental network costs. Demand investment/closure decisions tend to be open-ended and independent of each other, so:

- **<u>Increased</u> demand at one location**: An increase in demand at a location does not tend to cause a corresponding closure of existing demand at a different location. More realistically, an increase in demand would cause an increased requirement for increased generation, so its impact would best be reflected by modelling a pro-rata increase in generation.
- **<u>Reduced</u> demand at one location**: A reduction in demand at a location does not tend to cause a corresponding increase in other demand at other locations. More realistically, a reduction in demand would cause a reduced requirement for generation, so its impact would best be reflected by modelling a pro-rata reduction in generation.

Better reflects the different generation scaling used by SQSS and CBA for Demand Security and Economy

<u>How SQSS scales generation</u>

Demand Security Planned Transfer conditions (as reflected by Peak Security Background) scales generation to meet demand:

- "*C.2.1. For stations powered by wind, wave, or tides, AT = 0. This zero factor is set for the Security planned transfer condition so that there is confidence that there is sufficient transmission capacity to meet demand securely in the absence of this class of generation."*
- *All other power stations are scaled equally "…applying a scaling factor to their registered capacity proportional to an availability representative of the generating plant type at the time of ACS peak demand <u>such that their aggregate output is equal to the forecast ACS peak demand</u>") (C.5 SQSS)*

Economy Planned Transfer conditions (as reflected by Year Round Background) scales generation to meet demand:

- *"In the Economy planned transfer condition the registered capacities of certain classes of power station are scaled by fixed factors… <u>The NETS SO will review the appropriateness</u>*

of these factors and revise them where necessary, based on alignment with cost benefit analysis. The period between reviews shall be no more than five years, but may be less if required." (E.4 SQSS, emphasis added)

"*All remaining power stations and on the system at the time of the ACS peak demand are considered contributory and their output is calculated by applying a scaling factor to their registered capacity such that their aggregate output is equal to the forecast ACS peak demand minus the total output of directly scaled plant*." (E.5, SQSS, emphasis added)

How Network Options Assessment CBA scales generation to meet demand:

- NOA is used to: "*Recommend the most economic reinforcements, whether infrastructure build or alternatives, for investment over the coming years, to meet bulk power transfer requirements as outlined by the ETYS."*
- *"The model is set to simulate 365 days per year, 20 years into the future with an appropriate time resolution. The year in which an option is commissioned can be varied. The primary output from the tool for the cost-benefit analysis process is the annual transmission constraint forecast; there are further outputs that help the user identify which parts of the network require reinforcement." (NOA methodology)*
- *NOA demand and generation capacities taken from the NG ESO Future Energy Scenarios (FES)*

How FES scales generation to meet demand

"*Transformation of the whole energy system is achievable, and can deliver energy that is clean, secure, affordable, and fair. This requires strategic and holistic development of the networks, markets and technologies required, in a coordinated and timely manner, to ensure we make the most of the abundant renewable energy we could use to meet energy demand*." (FES 2022, page 100, emphasis added)

2) Better effective competition for GB generation vs international markets

An effect of the modification would be to reduce average generator Wider TNUoS charges. This would reduce competitive distortions for transmission connected generation and large distribution connected generators in GB, who pay TNUoS charges, compared with generators in international markets and small distribution connected generators in GB, who do not pay GB TNUoS charges.

3) Better effective competition between GB generation and demand

More level playing field of price signal between voltage of connection, co-location, or behind customer meters

i) **Locational signals**: Reduce distortion caused by demand "floor at £zero" and make demand and generation locational charges more equal/opposite.

ii) **Residual charges**: Reduce magnitude of both Demand Residual and Generator Adjustment Credit:

- Better enable demand to take action to reduce their own TNUoS charges because demand Residual charges are reduced as more of demand charge is weighted towards locational instead of Residual.
- Reduce distortions caused by different parties being exposed to different adjustments, or residuals. Better align the business case for generation and demand across different voltages, co-located arrangements, and behind customer meters.

Draft legal text

The modification proposes the following change to the CUSC legal text:

> "*14.15.27 Using these baseline networks for Peak Security and Year Round backgrounds, the model then calculates for a given injection of 1MW of generation at each node, with a corresponding 1MW reduction of generation ~~offtake (net demand)~~ distributed across all generation ~~demand~~ nodes in the network, the increase or decrease in total MWkm of the whole Peak Security and Year Round networks. The proportion of the 1MW reduction of generation ~~offtake~~ allocated to any given generation ~~demand~~ node will be based on the total background nodal generation ~~net demand~~ in the model. For example, with a total net GB generation ~~demand~~ of 60GW in the model, a node with a generation ~~net demand~~ of 600MW would contain 1% of the reduction of generation ~~offtake~~ i.e. 0.01MW.*"

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;	**Positive** Improves competition by reducing competitive disadvantage of generators who pay expensive GB TNUoS charges (transmission connected and large distribution connected), compared with generators in other countries and markets who do not. Also improves effective competition with small distribution connected generators and demand. Improves predictability of TNUoS charges. Further details, see response to "Proposers solution?" above

(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);	**Positive** More cost reflective of the drivers of network investment according to a CBA and SQSS. Further details, see response to "| Proposers solution?" above
(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;	**Positive** There appears to be a growing difference in average locations of generation versus demand. This means any detrimental impacts caused by using an inappropriate Reference Node is already large and likely to worsen over time. This adds to the importance of addressing this defect in a timely way.
(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.	**Neutral**
**The Electricity Regulation referred to in objective (d) 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.	

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	**Positive** [By making charges more cost reflective and improving effective competition, this will tend to make it easier for other policy tools to deliver safety and reliability of the system.

Lower bills than would otherwise be the case	**Positive** By making charges more cost reflective and improving effective competition, this will tend to incentivise more efficient investment decisions for both generation and demand users. This will tend to result in a more economically efficient energy system at lower total system cost and a lower cost to customers over the long term.
Benefits for society as a whole	**Positive** By making charges more cost reflective and improving effective competition, this will tend to incentivise more efficient investment decisions for both generation and demand users. This will tend to result in a more economically efficient energy system at lower total system cost and a lower cost to customers over the long term.
Reduced environmental damage	**Positive** By making charges more cost reflective and improving effective competition, this will tend to incentivise more efficient investment decisions for both generation and demand users. This will tend to result in a more economically efficient energy system at lower total system cost and a lower cost to customers over the long term.
Improved quality of service	**Positive** By making charges more cost reflective and improving effective competition, this will tend to incentivise more efficient investment decisions for both generation and demand users. This will tend to result in a more economically efficient energy system at lower total system cost and a lower cost to customers over the long term.

When will this change take place?

Implementation date
01 April 2026.

Date decision required by
Sufficiently before implementation to give users sufficient notice to appropriately take the change into account in their contractual terms and commercial decisions.

Implementation approach
The only change that would be required would be to the way the Tariff and Transport model calculates tariffs. There would be no change to the structure of the tariffs, or any other aspect of charging.

Proposer's justification for governance route
Governance route: Standard Governance modification with assessment by a Workgroup

It will be important to ensure the views of industry participants are appropriately taken into account.

Interactions

☐Grid Code	☐BSC	☐STC	☐SQSS
☐European Network Codes	☐ EBR Article 18 T&Cs[2]	☐Other modifications	☒Other

This Proposal has been developed through the TNUoS Task Force and has interactions with other TNUoS Task Force work.

Acronyms, key terms and reference material

Acronym / key term	Meaning
ACS	Average Cold Spell
ALF	Annual Load Factor
BSC	Balancing and Settlement Code
CBA	Costs, Benefits, and Assumptions
CfD	Contracts for Difference
CMP	CUSC Modification Proposal
CUSC	Connection and Use of System Code
EBR	Electricity Balancing Regulation
ESO	Electricity System Operator
ETYS	Electricity Ten Year Statement
FES	Future Energy Scenarios
MWkm	Mega Watt Kilometres
NETS	National Electricity Transmission System
NETS SO	National Electricity Transmission System Operator
NOA	Network Options Assessment
STC	System Operator Transmission Owner Code
SQSS	Security and Quality of Supply Standards
T&Cs	Terms and Conditions
TEC	Transmission Entry Capacity
TNUoS	Transmission Network Use of System
£/MWh	Pounds Mega Watt per kilometre

Reference material

- None

[2] 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 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.