Access and Forward-Looking Charges SCR: Consultation on *Minded-To Positions*, June 2021

Fred. Olsen Renewables' Response

Dr Graham Pannell, August 2021.

Response to: [Access and Forward-looking Charges Significant Code Review - Consultation on Minded to Positions | Ofgem]

Fred. Olsen Renewables is one of the leading independent renewable power producers in the UK, developing and operating wind farms in the UK since the mid-1990s. Our operational wind farm portfolio comprises a total generating capacity of 530 MW in GB and we have an extensive pipeline of projects – spanning offshore, onshore and emerging technologies. We are members of the representative bodies RenewableUK, Scottish Renewables and IREGG, and have also contributed to their responses.

Connection Boundary

3a. Do you agree with our proposals to remove the contribution to reinforcement for demand connections and reduce it for generation? Do you think there are any arguments for going further for generation under the current DUoS arrangements? Please explain why?

The Minded-To Position delivers a lack of locational signal for demand, with too little protection for bill-payers. We understand that charging must align with broader strategic objectives, for example facilitating wider take-up of EVs, however the proposals here apply to *all* demand, including high-carbon users, and intensive users such as data-centres, which will now see little incentive for HV-scale demand to locate near renewable generation nor where network capacity is available. This disbenefit is compounded by the Targeted Charging Review (TCR) decision to floor the location demand TNUoS signal at zero[1] – i.e. there are no credits for moving demand further North in GB. The resulting asymmetry of charging signals cannot deliver best value for consumers.

We note that the CEPA-TNEI modelling shows an increased net benefit by retaining some reinforcement cost signal for demand. If there is a concern specific to LCTs such as EVs and heat pumps, we suggest it would be better value for consumers if these technologies were given a targeted exemption from reinforcement costs, rather than a blanket exemption for all types of electricity demand.

3b. What evidence do you have on the effectiveness of the current connection charging arrangements in being able to send a signal to users and what do you think will be the effect of our proposed changes? How does this vary between demand and generation connections?

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[1] TCR decision, December 2019: [Targeted Charging Review: Decision and Impact Assessment | Ofgem]

3c. What are your views on the effectiveness of the current arrangements in facilitating the efficient development and investment in distribution networks? How might this change under our proposals where network companies are required to fund more of this work?

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3d. Do you agree whether the need to provide connection customers with certainty of price reduces the potential for capacity to be provided through other means such as flexibility procurement? How might this change under our proposals?

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3e. What are your views on whether we should retain the High Cost Cap? Is there a case for reviewing its interaction with the voltage rule if customers no longer contribute to reinforcement at the voltage level above the point of connection?

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3f. What are your views on the recovery of the costs associated with transmission that are triggered by a distribution connection? Does this need to be considered alongside wider charging reforms or could a change be made independently?

This brings undue discrimination to Scottish connection customers. Projects either side of the border but in the same electricity system, which are otherwise similar in engineering terms, face enormously different signals based on an out-dated view of which licensee ('D' or 'T') is custodian of 132kV assets. This distortion is exacerbated by the Minded-To decision, making an unfair situation worse.

More explicitly, an EHV or HV customer in Eng&Wales triggering 132kV reinforcements will face no up-front connection cost signal for that reinforcement. An EHV or HV customer in Scotland triggering 132kV substation reinforcements will face 100% of the costs of that reinforcement in advance of connection. This Scottish distribution customer is also unfairly treated compared with a transmission-connectee of the same size at the same GSP, as the latter can spread the cost of transmission reinforcements over a number of years.

Noting the DNO 'heat maps' for prospective DG connections, it can be seen that the majority of GSP substations across Scotland are close to a threshold for requiring reinforcement, and hence this distortion could become a major barrier to new deployment – this effect is likely most pronounced for new renewables deployment, and hence will have negative consequences for the least cost path for net zero.

A reasonable level playing-field outcome for connection customers in Scotland is necessary to realise the benefits which Ofgem has set out in the Minded-To publication. Two options to mitigate this problem are:

i. Effect code changes such that transmission reinforcement costs have a similar effect to EHV distribution reinforcement costs
ii. Reconsider how onshore 132kV circuits are treated under connection charging methodologies, to bring better alignment across the England/Scotland border.

Such solutions could be implemented independently of wider charging reforms, and should not be unduly delayed.

3g. What are your views on the likelihood of inefficient investment under our proposals (e.g., an increase in project cancellations after some investment has been made)? Are there good arguments for further considering introducing liabilities and securities to mitigate this risk?

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3h. What are your views on whether the interactions between our connection reforms and the ECCRs must be resolved before we are able to implement our proposed reforms? How do you factor in the effects of the ECCRs (if at all) into decision making, given the levels of uncertainty around subsequent connectee(s)? What suggestions do you have to make our policy and the ECCRs work together most efficiently?

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Access Rights

4a. Do you agree with our proposal to introduce better defined non-firm access choices at distribution? Do you have comments on their proposed design?

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4b. Do you agree with our proposal to introduce new time-profiled access choices at distribution? Do you have any comments on their proposed design?

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4c. Can you identify any benefits to shared access rights, which would indicate we have underestimated the likely take-up?

No strong advantages for shared access rights, and we agree with the disadvantages presented. The potential advantages of shared access rights can generally be provided instead through innovation and flexibility (in the broader sense of the word) in connection design and in connection offer contracts, such as via affordable and local active network management schemes, without being tied explicitly to specific users' sharing of access rights.

4d. Do you have any comment on our proposed choice about how to reflect access rights in charges (i.e. connection and/or distribution use of system charges)?

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4e. Do you agree with our proposal to not prioritise the introduction of new transmission access choices as part of this Significant Code Review?

The prioritisation is understandable.

4f. Do you have views on how access rights should be standardised across DNOs?

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4g. Do you have any views on our proposed timescale of 1 April 2023 implementation?

Agreed.

TNUoS Charges for SDG

5a. Do you have any evidence that SDG does not contribute to flows in the same way as large generation and, therefore, should not be charged on a consistent basis?

Our principle concern is that TNUoS itself is not cost-reflective and does not properly take account of the developments in transmission licensees' transmission businesses. Therefore it would be inefficient to apply this incorrect locational signal to more system users. Our second key concern is that the quantitative analysis is flawed to the extent that the Minded-To Position may bring a net disbenefit to consumers, as detailed in our answer to question 5e.

If TNUoS was to be implemented on SDG, there are at least two elements that must be considered to reduce the effective chargeable capacity of SDG relative to transmission connected generation:

1. A factor which recognises local use of power on the distribution system, effectively reducing the chargeable capacity for TNUoS, but without adding undue volatility – for example, avoiding binary criteria of certain GSP substations being eligible and others not, which would send an excessively unpredictable cost signal. To implement a local-use factor, a very broad average of the proportion of SDG power consumed on the relevant distribution systems may be a useful starting point, aligning with TNUoS's Long-Run Incremental Cost (LRIC) approach.
2. The electrical losses between the SDG meter and the higher voltage transmission circuits which connect to a GSP, which gives effect to a lower transmission entry capacity (even without the effects of local distribution-connected demand).

We would be strongly opposed to any "cliff-edge" approach – such as only applying charges based on certain GSP criteria. This could result in customers coming in or out of eligibility for the charge, often after connection and as a result of other users' investment decisions – this flip-flop effect will be damaging to confidence in the signal, and unduly drive up risk premia for investment.

From the options presented for SDG, we agree that inverse demand charging is a poor option (and note interactions with TCR, which will floor locational demand TNUoS). We explain in our answer to question 5b why a threshold of '16A per phase', in keeping with ER G98 and G99, is a justifiable lower limit.

5b. Do you agree with our threshold for applying TNUoS generation charges of 1MW? If not, what would be a better threshold and why?

We are very concerned by the proposal to remove the EET floor and introduce a perverse incentive for any generation below a TNUoS threshold to *cease* generating during triad, which will add cost elsewhere in the system to compensate. However, we seek reassurances that this distortion will be mitigated following TCR implementation – because locational demand TNUoS will be floored at zero, conversely, we infer that there will be no EET charge? We ask Ofgem to confirm this in subsequent communication to the industry.

Regarding the threshold, if following a wider review and revised analysis TNUoS was applied to SDG, then we would favour the most level playing field – and this would entail applying the same framework to *as small a threshold of generation as can be practically achieved*. To this end:

- We note that SHEPD, SHET and ESO has successfully managed a threshold of 40kW in considering transmission impact assessments for new generation on Kintyre.
- We note that SPD, SPT and ESO has successfully managed a threshold of 100kW in considering transmission impact and system protection for new generation in South-West Scotland.

We do not see a reason why a 0.1MW, 0.5MW, 5MW or 20MW SDG should be treated differently under use of system charging (in fact this this same logic applies to 132kV-connected users in Scotland, considered "transmission connected" although the 132kV system in Scotland is increasingly more used as distribution). We agree that there will be a practical minimum limit for efficient administration, but propose that this limit is much smaller than 1MW.

A relevant technical threshold is found in ENA Engineering Recommendations G98 and G99 – where G98 applies to generators of up to 16A per phase, and G99 applies to anything larger. DNOs should be able to readily identify which generators are required to comply with G99, as opposed to G98; they can be expected to have individual records of G99 generators but may not do so for the G98 generators. We propose therefore that the **"16A per phase" threshold for generators under the remit of ER G98 is a better limit**.

5c. Do you have any evidence that distribution connected generation at a grid supply point has a different impact than directly connected generation?

We see this as the same question as 5a. Please consider our answer as an exact copy & paste from 5a.

5d. Do you have a preference for one of our options for addressing the local charging distortion? If so, please indicate which option and provide your reasons. Are there any options we have missed?

We agree with point 5.21 (and 5.6) of the consultation that states this is not a priority area for reform, especially given the scope and necessary speed of a wider TNUoS review, in order to least deviate from the lowest-cost pathway to deliver net zero.

5e. Do you support our position that we should consider transitional arrangements? If so, do you have a preferred option and evidence to support the benefits or risks associated with each option?

Yes, we support transitional arrangements. Summarily:

A. We welcome the acknowledgement that the Government's net zero ambitions and Ofgem's own strategic direction drive the case for a wider TNUoS review.
B. We believe revised quantitative analysis (on TNUoS for SDG) is essential to address the points we raise below; but that it would be sensible to perform this revised analysis after getting clarity on the outcomes of a wider TNUoS review.
C. Application of TNUoS to SDG should be paused and subsequently reconsidered in light of the revised analysis.
D. In the interim, "quick fixes" to mitigate the imperfect locational TNUoS signal will be necessary to maintain a low-cost pathway to net zero.

With regards Table 10 under consultation point 5.25, this most aligns with the option "*Confirm intention to address issue but delay until greater clarity about strategic direction*".

We've added some specific evidence of the impact of the proposals further down in our answer. First, we address a number of the flaws in the quantitative analysis, which has produced misleading conclusions. The case for wider TNUoS and "quick fixes" is explored in our answer to question 5g.

Concerns with the Quantitative Analysis

The quantitative analysis associated with the minded-to position has a range of significant flaws, which we detail below. We raise this because:

- Corrected analysis is likely to show a net increase in carbon emissions.
- Corrected analysis will show a significant (and necessarily rapid) increase in government support costs.
- Corrected analysis could credibly show the proposals to be a net disbenefit to consumers.

Although Ofgem gives weight to a principles-based decision, nonetheless the potential for a net disbenefit and increased carbon emissions is a material consideration, and revised analysis is necessary before committing to a structural change in network charging of this magnitude. We welcome your consideration of a wider TNUoS review and propose that revised analysis should follow-on from such a review before committing to apply TNUoS to SDG.

We wrote to you on 5th August detailing our queries relating to the quantitative analysis and requesting some clarification to assist this response. We have received no response of any kind.

It is welcome that a number of the flaws have been acknowledged in the report – such as the unrealistic assumptions around planning consent and the unknown pipeline for replacement projects in other regions – but there are further issues which call into question the resulting conclusions. Key flaws include:

i. Misapplication of TNUoS credits
ii. Misapplication of revenue-replacement support costs

iii. Assumptions of sufficient and timely delivery pipeline in southern regions
iv. No adjustment of nameplate capacity to compensate for lower average load factor generation
v. No recognition of geographic diversity benefits of variable renewables
vi. No adjustment of flexibility requirements to meet the less diverse and lower load factor generation mix.
vii. Assumptions of zero early closures

TNUoS credits have been misapplied in the modelling, mistakenly removing a signal to support triad generation by SDG. The sharper signal of TNUoS rather than the EET applied to southern generation would more likely see carbon emissions rise as a result of the proposed change. Quantitative Analysis p28 states “the reforms remove the operational incentive on embedded generators in the southern zones to export over expected Triad periods”, whereas ESO pays TNUoS credits based on the average output during triad, retaining the triad signal. A smaller but similar-direction effect comes from applying Ofgem’s Targeted Charging Review (TCR) decision to floor demand locational charges at zero; even if un-floored, this would remove any corresponding EET charge applied to eligible (Northern) SDG, mitigating the perverse signal to turn-off during triad, but also mitigating the claimed carbon emissions reduction.

Government support costs are mistakenly assumed to be tailored precisely to each region and separately to each generator technology (and without any delay which might impact deployment decisions). This is not representative of the CfD process, which has a single clearance price for all GB for a given ‘pot’ of technologies. This results in excess support for southern generation, which has the clearance price unduly lifted by the imperfect TNUoS locational signal. The resulting inefficiency will lead to a ‘support costs’ impact much larger than that which has been modelled.

It is also an optimistic assumption that the revenue ‘loss’ through TNUoS change will be perfectly offset in time and that there will be no investment delay and no risk premium adjustment as a result of the changes. The timing element has only downside risk for the quantitative analysis. On a related point, it is optimistic to assume a seamless transition of pipeline projects from one region to another; revised modelling would allow for an appropriate lag.

We note that geographic diversity of variable renewables has not been fully accounted in the modelling. The TNUoS signal to focus these renewables in closer proximity, in the centre and south of GB, corresponds to greater volatility of output, leading to extremes of pricing and greater requirements for balancing actions (increased balancing costs to consumers) and greater requirements for flexibility (more nameplate capacity of battery storage or similar for each MW of variable renewables). When correctly factored in this will act against the claimed benefit.

Additionally, among the acknowledged modelling flaws a few are worth drawing out as the implications are very material to the possibility of any benefit or disbenefit coming from the proposed change.

According to the 2021 FES report[2], in the consumer transformation scenario (the main scenario used by Ofgem in its analysis) we will need 44GW of onshore wind by 2050, which in terms of resource is mostly expected to be deployed in Scotland. The modelling acknowledges the limitations of pipeline

[2] https://www.nationalgrideso.com/future-energy/future-energy-scenarios/fes-2021

and consent for this technology to be located in southern areas, and that most of the resource is in the north. Setting aside the considerable planning barriers, more southerly onshore wind is acknowledged to have lower factors on average; and to maintain the energy output for net zero pathways more nameplate capacity would be required to be deployed, with corresponding increase in land use and support costs (typically paid per MW). We note in Ofgem's podcast on the minded-to position[3] the view that reduced onshore wind may see an increase in English solar generation. Noting the roughly four times lower load factor of solar, this means significantly more nameplate capacity will be needed – which brings questions for total embodied carbon, of increased support costs and increased land requirements. We suggest it would be appropriate to quantify these outcomes to seriously test whether the changes can provide an overall net benefit.

Another significant element is the risk of early closure of operational renewables in Scotland as a result of the changes. Projects exiting previous support schemes (such as the RO) or ending their CfD agreement when faced with such tariffs as shown in Table 5.3 of the quantitative analysis (copied above) will see a challenging, and in a number of instances negative, cost-benefit for future maintenance, resulting in early closures. Both the unused local grid infrastructure and the negative effect on total deployment are missing from the quantitative analysis, which assumes existing renewables remain on the system without additional cost

Project Impacts

[redacted].

5f. Have we identified all the options for administering TNUoS generation charges for SDG? If not, what options have we missed, and why would they be preferable to those we have identified? Can you provide any evidence regarding the implications of the different administrative options for your business?

Obliging all SDG, particularly with a small threshold, to enter into individual access agreements with the ESO is an unnecessary administrative burden. This would only be justified if the SDG was being provided financially firm access to the transmission network, requiring individual compensation arrangements.

It would be more efficient to make better use of existing arrangements. DNOs already maintain embedded capacity registers, and can be expected to make a non-aggregated version of these databases available to the ESO for this billing purpose. Furthermore, DNOs already use "Developer Capacity" in communication with the ESO to determine transmission reinforcement and related user commitment requirements. Additionally, building on our answer to question 5a, the DNO is in the best position to maintain a record of the "local-use" and "loss-adjustment" factors we have proposed for adjusting SDG capacity for TNUoS purposes. Therefore we propose that the simplest method is for the DNO to maintain the record of agreed capacities for charging purposes, which the ESO can view, and that each generator should have the opportunity to view and ratify its own chargeable capacity in communication with the DNO (as it can already discuss how it is recorded on any embedded capacity register).

[3] https://soundcloud.com/user-967817983/accessandforward-lookingchargesconsultationoverview

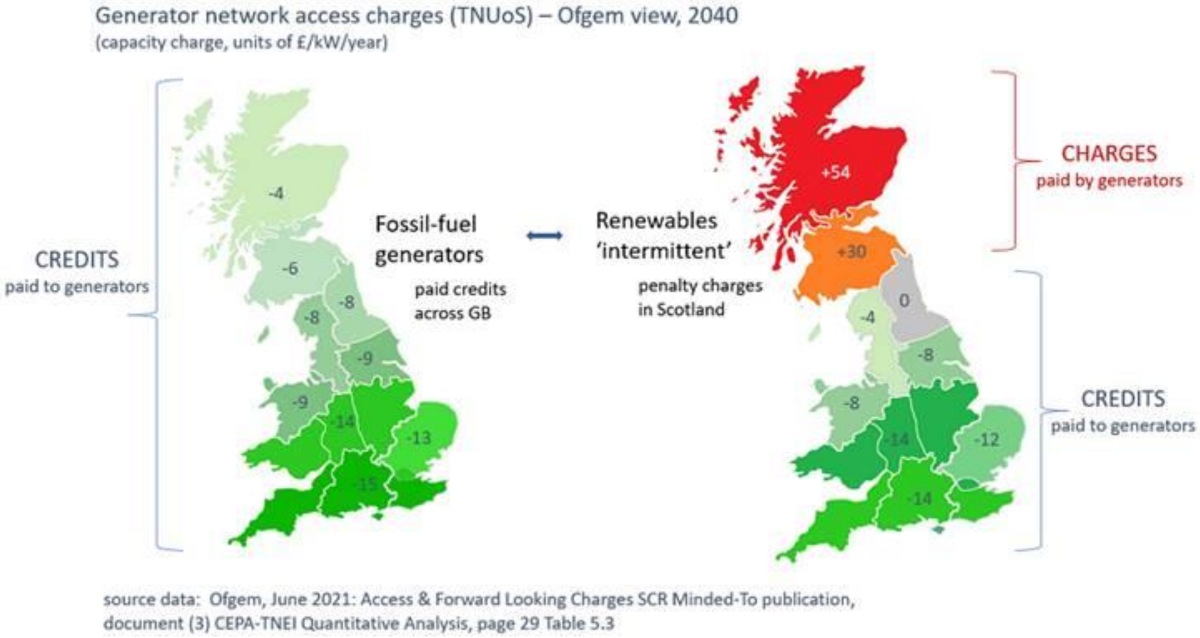
The administration of charging is then most simply done by billing through the supplier. This replicates what is done for demand TNUoS, so uses the existing billing relationship between ESO and supplier. For the generator, this will be seen as an additional line item to a supplier bill which already contains DUoS, which is logical and gives the least additional administrative burden.

5g. Are there any specific issues you think we need to consider, as part of our work on the future role of network charges? Why are these important to consider?

The primary charging distortion is the wider TNUoS signal itself – which substantially over-states the incremental cost of new network capacity in the North. It is based on a small set of new 400kV pylon line costs, when this is not how the ESO and TOs have provided new grid capacity. We have seen a 250% increase in average generator wider TNUoS tariffs in Scotland over a decade where TO spend has dropped 7% in real terms [Nera, SSEN – see answer to question 7 for references].

There are further valid questions of TNUoS – can the signalled benefit of TNUoS credits ever be realised by the system? – should credits be paid at all? Should TNUoS more explicitly account for the benefits of geographical distribution of variable renewables? - providing a better 'spread' of power output and reduced extremes, with consequential benefits for wholesale market volatility, capture rates and requirements for system flexibility. Finally, as Ofgem note, is the TNUoS signal compatible with the required system changes to meet net zero?

Furthermore on the case for reform – we note with alarm the capacity charges modelled to apply in 2040, as posted on Table 5.3 of page 29 in the quantitative analysis document. This shows that the current methodology is set to pay credits to all fossil-fuel generation all across GB, while charges are <u>only</u> recovered from generators in Scotland, and only from renewables and 'low carbon' generation. It is difficult to reconcile these charges against cost-reflective network development nor against the deployment requirements of net zero. The data from Table 5.3 is illustrated below:



In conclusion, **we strongly support the case for wider TNUoS reform**. Furthermore, to maintain the necessary scale of generation deployment for least-cost net zero pathways, **quick fixes to mitigate the existing distortions of TNUoS will also be necessary**. Quick fixes can include:

- Reduce the TNUoS Expansion Constant, to better reflect the work of Transmission Owners and mitigate the over-estimation of locational TNUoS.
- Eliminate generator wider TNUoS credits, mirroring the TCR decision to floor locational demand TNUoS.

Other Information

7. Do you have any other information relevant to the subject matter of this consultation that we should consider in developing our proposals?

[redacted]

General Feedback

1. Do you have any comments about the overall process of this consultation?
2. Do you have any comments about its tone and content?
3. Was it easy to read and understand? Or could it have been better written?
4. Were its conclusions balanced?
5. Did it make reasoned recommendations for improvement?
6. Any further comments?

General feedback has been supplied to the stakeholders@ofgem.co.uk address.