Email to:
FutureChargingandAccess@ofgem.gov.uk

25 August 2021

To whom it may concern,

**Access and Forward-looking Charges Significant Code Review: Consultation on Minded to Positions**

Scottish Renewables is the voice of Scotland's renewable energy industry, working to grow the sector and sustain its position at the forefront of the global clean energy transition. We represent around 260 organisations across the full range of renewable energy technologies in Scotland and around the world, ranging from energy suppliers, operators and manufacturers to small developers, installers, and community groups, as well as companies throughout the supply chain.

In responding to this consultation, we would like to draw your attention to the following points:

- We welcome the proposal of removing the contribution to reinforcement for demand connections and reduce it for generation, but we would like to note that it is difficult to assess the outcomes of this without knowing what will happen with DUoS.
- We think that a better defined non-firm access must be introduced in a way that embedded generators are able to predict when curtailment is likely to happen.
- We believe that the current TNUoS charging regime is not fit for purpose to deliver an economically efficient transition to net-zero. Therefore, we strongly support the proposal that reassesses TNUoS charges for SDG after a wider review of TNUoS has happened.
- We think, if implementation of TNUoS charges for SDG were to be progressed, there is a strong case for grandfathering sites that will be adversity affected by regulatory changes. This is mainly because big changes to the regulatory environment during the operation phase will harm investor confidence.

Scottish Renewables would be keen to engage further with this agenda and would be happy to discuss our response in more detail.

Yours sincerely,

Angeles Sandoval

**Policy Manager**

Scottish Renewables

## Connection boundary

**Question 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.**

We welcome Ofgem's proposal of removing the contribution to reinforcement for demand connections and reduce it for generation. We think that this new arrangement will send an effective signal for network users and may speed up the roll-out of low carbon technologies.

However, it is difficult to assess what the net outcome will be without having clear details about what will happen with DUoS charging arrangements. Ofgem states that they are still considering policy options for DUoS charging structure and the current assessment of the connection charging proposals is based on the assumption of either no or little change to DUoS.

**Question 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?**

The current "shallow-ish" connection boundary incentivises connection in locations which do not require reinforcement. We think that this approach could limit the economic locations available to renewable generation, and prevent wider networks upgrades that may enable the decarbonisation of other sectors of the economy, for example transport or heat. We believe the current arrangements will constrain the roll out of low carbon technologies and the increased investment we will need to electrify heat and transport without the proposed changes.

Scottish Renewables and Renewable UK have shown[1] that a move to a shallow connection boundary arrangement could address this problem, so new generators are only required to pay for direct cost of connection. However, a shallower connection boundary needs to be introduced in a way that protects the rights of existing users, who could otherwise lose out via higher DUoS charges due to the effect of new connectees on the network.

Ofgem is proposing a hybrid approach that would remove the contribution to reinforcement for demand (a "shallow" connection charging boundary) and reduce it for generation (a "shallower" connection charging boundary than exists today). We think that this is a sensible approach and will provide balance between removing barriers, encouraging more efficient system development and supporting net zero at least cost. However, we would like to highlight that this must be looked at carefully with the policy options of DUoS charging structure that Ofgem is still considering.

Additionally, we think that Ofgem should consider the option of grandfathering the rights of existing connectees. Previously, connectees would have paid for reinforcements. If new users connect without paying such costs under a shallower connection boundary, these costs will be reflected in network charges, which will be a negative externality on existing users (unless locational elements of DUoS offset the reduced connection costs). This could in turn increase the perceived regulatory and policy risk for future projects, driving up cost of capital and ultimately power prices for consumers. Grandfathering is therefore the preferable option to maintain investor confidence and least cost for consumers.

[1] Grid charging reforms: New report by Baringa consultants for SR/RUK (scottishrenewables.com)

**Question 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?**

As we mentioned in our answer to question 3b, the current arrangements represent a barrier for current network users. We think that this new proposal will facilitate efficient development and investment in distribution network, allowing network users to invest considering anticipated network needs.

We also think that this proposal could have some positive consequences to stimulate the use of flexibility across DNOs, since they can find more efficient ways of funding the work needed. The CEPA-TNEI report that comes alongside the consultation, suggests that the emergence of flexibility services could help to mitigate some impacts of a shallower connection boundary if changes to connection policy do stimulate the emergence of flexibility markets. Therefore, we can see that this proposal combined with a set of policies that push the emergence of flexibility services across the UK, could have positive impact in the smart and flexibly energy system that we expect to have by 2030.

We would like to note that if network companies (DNOs) have to fund the upgrades to the distribution system, these upgrades will either be in the RIIO-ED2 business plans or come from a Re-opener. If they are part of a Re-opener, the Ofgem approval process shouldn't delay the grid investment. Otherwise, this could delay the connection (or optimal running) of the renewable assets. In addition, adding a greater level of detail to the Re-opener guidance could facilitate stronger proposals from DNOs, further supporting swift decision-making from Ofgem.

**Question 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?**

Price certainty is critical to deliver the volumes of renewable generation net zero requires, as it lowers risk and cost of capital, thus benefitting consumers. It is our view that that flexibility procurement should be delivered through flexibility markets not charging volatility. By 2030 and 2050 we need a huge volume of renewable generation, so adding volatility of prices will only amplify the risk for investors, which will ultimately be placed onto consumers to pay.

**Question 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?**

No comments.

**Question3f: 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 disproportionately and unduly disadvantages Scottish connectees, owing to the lower voltage boundary between transmission and distribution. Consider two connections, alike in physics and engineering, at an HV or EHV level and each triggering 132kV substation reinforcement – in England & Wales this connection will receive no reinforcement cost signal whereas in Scotland the user will be liable for the full cost in advance for the 132kV substation reinforcement. This distortion already exists but is made worse by the proposed change in connection boundary. Acknowledging the SHEPD and SPD "DG heat maps", it can be seen that a significant majority of 132kV "GSP" substations across Scotland are close to or at their capacity to accommodate further generation, which means that this problem is material.

To meet the deployment rates of new renewables stipulated in FES or CCC's carbon budget, a solution to this distortion is necessarily a priority. Two options available are to either (i) bring the application of costs of transmission reinforcement triggered by distribution users more in line with the allocation of higher-voltage distribution reinforcements, or (ii) reconsider how onshore 132kV circuits are treated under connection charging methodologies to bring better alignment.

We think that these changes must be considered alongside a wider review of TNUoS. If Ofgem introduces TNUoS charges for SDG, these users could also face higher costs compared to those on transmission. SDG would face the same ongoing network charges, but also an upfront connection charge in relation to transmission costs that a transmission connected generator would instead pay over several years. This could lead to a further distortion between transmission and distribution connected generation.

**Question 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?**

No comments.

**Question 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?**

No comments.

**<u>Access rights</u>**

**Question 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?**

We think that a better defined non-firm access without being able to clearly forecast and understand the levels of curtailment is very unhelpful. Embedded generators need financial firm access rights and for this they need to know when curtailment is likely to happen. For example, a solar project that experiences a % of curtailment during the night or day will have a completely different impact in value. Similarly for wind, which has a more random generation profile than solar, detailed information will need to be given for analysis of when such % of curtailment could happen.

We believe it would be appropriate for Ofgem to commit to review the security of supply standards at distribution which will facilitate financially firm access as a result. Ruling out financially firm access means unnecessarily implementing a distortion between distribution and transmission connectees. There is a risk that if SDG is paying generation TNUoS on an equivalent basis as transmission generation, but without financially firm access, then it will be overcharged for the grid access rights it has.

**Question 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?**

New time profiled access choices will bring some benefits in relation to the speed and simplicity of connections. However, Ofgem has not clarified how would the new access arrangements interact with DUoS, which makes it very difficult to assess the final outcomes of this proposal. We would welcome a commitment from Ofgem on a timeline to review new access arrangements, and bring further certainty to generators.

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

No comments.

**Question 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)?**

No comments.

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

No comments.

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

No comments.

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

Assuming this is only referring to Access right implementation, this timeline is acceptable.

<u>**TNUoS charges for SDG**</u>

**Question 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?**

We think that without a wider review of TNUoS, charging SDG in the same way as large transmission generators is not the best way forward. In question 7 we explain in detail the key reasons why TNUoS needs to be reformed and in question 5e we also explain why delaying implementation and grandfathering projects are our preferred options.

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 "cliff edge" binary criteria of certain GSP substations being eligible and others not, which can change over the life of operational projects, sending an excessively volatile and unpredictable cost signal which would add an unnecessary risk premium to generation finance. 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 approach.
2. The electrical losses between the SDG meter and the higher voltage transmission circuits which connect to a GSP.

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

The current proposal will apply TNUoS charges to all generators, except for <1MW SDG, which would continue to face the embedded export tariff (EET) with the cap removed.

We would like to note that removing the cap of generators below 1 MW would affect producers in Scotland and northern distribution zones, who currently pay no charge but would face charges for export during Triad periods under this proposal. The qualitative impact assessment from CEPA-TNEI shows that while microgenerators today in the north of Scotland faces embedded export charges equal to 0 £/kW, by 2024 and 2040 this charge will be around 36.5 and 80.6 £/kW. This sends a perverse signal to generators for not generating at Triads periods.

We would favour a level playing field – and this would entail applying the same framework to as small a threshold of generation as can be practically achieved. A technically sound threshold is that set between Engineering Recommendation G98 (for generators of up to 16A per phase) and G99 (for all other generation); wherein DNOs can be expected to have individual records of all G99 generation, but may not have accurate individual records for G98 generation.

We note that thresholds smaller than 1MW have been used by DNOs in consideration of planning studies; SSEN has used a 40kW threshold in one region, and SPEN has used 100kW in South-West Scotland, in considering relevant projects for transmission study. We also note that wider BM participation is being encouraged by the ESO, and that BMUs can contain aggregations of smaller units. Finally, we see smaller than 1MW projects recorded in Embedded Capacity Registers, typically aggregating at HV and LV networks mostly for simplification of presentation; again, noting that a significant threshold for DNOs own records is the boundary between G98 and G99 generation.

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

Please see answer to 5a.

**Question 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.

**Question 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 the option "**to confirm intention to address the issue but delay until greater clarity about strategic direction**"**:**

- We believe that it is not clear if the **current charging regime is the right one to deliver an economically efficient transition to net-zero** – we would welcome a meaningful, strategic, and forward-looking review of charging in pursuit of this objective, to be delivered as soon as feasibly possible.
- **We agree that pausing application to SDG avoids unnecessary short-term volatility** and mitigates increased perception of regulatory uncertainty ("change fatigue"). Implementation without wholistic consideration of the wider issues with TNUoS would add finance cost to generation, ultimately being passed through as additional cost to consumers.

- **We feel there are significant flaws in the associated quantitative analysis** which need to be addressed to gain comfort that there is an overall net benefit, and that such analysis would have to be reworked in any case in light of a wider review of TNUoS. We urge Ofgem to consider our feedback and revisit the analysis. To limit re-work, this revisited analysis may be most appropriately timed after a wider review of TNUoS.

We are concerned that the CEPA-TNEI analysis presents a misleading picture of the outcome, and that such analysis should be stress-tested both in light of the practical issues we raise, and also in terms of Ofgem's overall strategic aims and practical delivery of the UK's ambitions for achieving zero, before committing to implementation.

Finally, if implementation were to be progressed, it is our view that **grandfathering** projects could be an option to help reduce risk for investors. This is mainly because big changes to the regulatory environment during the operation phase will harm investor confidence. The industry has invested based on clear charging regimes – for renewables this investment is up front for long term assets with no ability to pass through cost changes. As a consequence, this could impact operational sites and it will increase the risk for new sites, which may mean that some development projects do not materialise.

We acknowledge that investment in the energy sector is not risk-free, and that investors should anticipate a certain level of variation in network charges over the life of the project. Indeed, industry make investments based on a realistic and reasonable assumption on the level of change to charging regimes. However, the introduction of transmission charges on generators who, if investing prior to 2016, would have seen TNUoS as a benefit, represents a substantive change in the framework they invested in.

We have the following evidence that supports our preferred options:

1. **Resulting Tariffs and Possible Reform**

We welcome the consideration of whether the wider TNUoS methodology will remain fit-for-purpose (2.29 – 2.31), and we are strongly supportive of such a review, in parallel with any necessary quick-fixes to the methodology, as we set out in more detail in our answer to 5g.

By way of example, we note the modelled tariffs out to 2040, showing the Wider Circuit TNUoS capacity charge averaged to each DNO region (quantitative analysis document, p29 Table 5.3), which stakeholders may infer as a direction of travel for the status quo methodology. The outcomes are a strong signal to incentivise fossil-fuel generation anywhere in England or Wales, and even to pay TNUoS credits to fossil-fuel generation throughout Scotland, despite the principles which TNUoS was designed to deliver. On the other hand, the only generation making payments for wider TNUoS is low carbon conventional and variable renewables in Scotland alone. These outcomes are hard to reconcile against cost-reflectivity, nor against reasonable regulatory uncertainty for existing generators. Above all, these outcomes are hard to reconcile with the deployment of variable renewables required to meet net zero pathways. The published table is summarised below for illustration (EET column):

| Dist. zone | Capacity charge £/kW, Conventional generators | Capacity charge £/kW, Low Carbon generators | Capacity charge £/kW, Intermittent generators |
|---|---|---|---|
| 1 | -3.56 | 54.02 | 54.46 |
| 2 | -5.72 | 29.17 | 29.91 |
| 3 | -7.67 | -0.24 | -0.17 |
| 4 | -8.32 | -4.55 | -4.26 |
| 5 | -8.97 | -8.86 | -8.35 |
| 6 | -8.97 | -8.86 | -8.35 |
| 7 | -13.55 | -18.44 | -13.86 |
| 8 | -13.55 | -18.44 | -13.86 |
| 9 | -13.17 | -16.37 | -12.04 |
| 10 | -13.55 | -18.44 | -13.86 |
| 11 | -14.69 | -19.48 | -13.74 |
| 12 | -13.55 | -18.44 | -13.86 |
| 13 | -14.69 | -19.48 | -13.74 |
| 14 | -14.69 | -19.48 | -13.74 |

Ofgem July 2021 - Access & Forward Looking Charges SCR Minded-To Publication - document (3) CEPA-TNEI Quantitative Analysis, page 29 Table 5.3

We believe that these tariff signals are indicative of the need for a wider review of TNUoS.

## 2. Material flaws in the Quantitative Analysis

The accompanying CEPA-TNEI quantitative analysis has a number of serious flaws which in our view provide misleading conclusions. We know that members wrote to Ofgem seeking clarification of the modelling detail, but that to date these concerns have not been addressed; we hope that these can usefully improve the analysis, notably in the case that the analysis needs to be repeated in light of a wider TNUoS review.

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. In our view a subsequent analysis which would take consideration of the issues which we have outlined below could well show that the minded-to position results in a net disbenefit to consumers and more certainly an increase in carbon emissions.

Key flaws include:

- Misapplication of TNUoS credits
- Misapplication of revenue-replacement support costs
- Assumptions of sufficient and timely delivery pipeline in southern regions
- No adjustment of nameplate capacity to compensate for lower average load factor generation
- No recognition of geographic diversity benefits of variable renewables
- No adjustment of flexibility requirements to meet the less diverse and lower load factor generation mix.
- 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

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. The result 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 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, we would point out that it is optimistic to assume a seamless transition of pipeline projects from one region to another.

We note that geographic diversity of variable renewables has not been fully accounted for 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.

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.

We acknowledge that investment in the energy sector is not risk-free, and that investors should anticipate a certain level of variation in network charges over the life of the project. However, the introduction of transmission charges on generators whom, if investing prior to 2016, would have seen TNUoS as a benefit (if they had factored it at all), represents a substantive change in the framework under which they invested.

According to the 2021 FES report[2], in the consumer transformation scenario (the main scenario taken 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 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 capacity factors on average; to maintain the energy output for net zero pathways more nameplate capacity would be required, with corresponding increase in land use and support costs (typically paid per MW). We note in Ofgem's podcast on the minded-to position 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 and repairs, resulting in early closures. Both the unused local grid infrastructure and the negative effect on total

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

deployment are missing from the quantitative analysis, which assumes existing renewables remain on the system without additional cost.

We conclude that a corrected quantitative analysis would show a reduced, likely negative net benefit, and that carbon emissions are more likely to rise than fall under the proposed changes. We are in full agreement that wider TNUoS needs to be reconsidered in terms of alignment with the UK's objectives for net zero and Ofgem's overall strategic direction. We agree that it would be appropriate to pause application of wider TNUoS to SDG while such reform is considered, mitigating change fatigue and undue volatility. We believe updated quantitative analysis would need to be done in light of the proposed review and the points raised above before confirming the implementation of this charge for SDG.

**Question 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?**

No comments.

**Question 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?**

It is our view that many issues are not included in the current charging proposal from this consultation that Ofgem should consider in the analysis of the future role of network charges. These include:

1. False Strength of Locational Signal

As supported by the evidence of real TO spend, published in the SSEN paper[3] of February 2021, Wider Circuit TNUoS overstates the strength of the charging signal. The methodology assumes an incremental cost of new 400kV pylon line in estimating additional grid capacity, when this in fact happens very rarely – the ESO and TOs have provided a large degree of capacity through non-build solutions, upgrades and reinforcements, or other "non-distance" improvements such as operational intertrips, which are all excluded from the present TNUoS methodology. As a result, the charging signal is significantly over-estimated. The minded-to document suggests that revenue gaps resulting from network charges will be offset by CfD increases, which will lead to significant economic distortion. The result is either unnecessarily lower-efficiency plant in the South unduly setting the auction clearance price, or an unnecessarily high auction clearance price to maintain deployment in the North, giving unduly higher revenues to plant in the South. In either case, the result will be inefficient.

2. Locational allocation of capacity.

As we mentioned previously, there are key determinants of the location of renewable capacity that are not captured in this model, mainly related to locational decision of investors that include load factors, grid constraints and transmission capacity investments. We recommend that the impact assessment considers the overall impact of benefits including locational factors such as load factors, price volatility and wind capture prices. These are factors that we think are important to consider as the quantitative potential benefit could be highly affected by them.

3. The benefits of a diverse mix of generation

The current TNUoS regime at transmission level already incentivises locating renewable generation in the centre and south of GB. Hence, if TNUoS charges are now applied to SDG this will only exacerbate this

[3] https://www.ssen-transmission.co.uk/news-views/articles/2021/2/ssen-transmission-calls-for-reform-of-unfair-and-volatile-charging-regime/

distortion, with much higher benefits for the development of solar energy in the south. This charging system is incompatible with the decentralised energy system of the future that the UK Government envisioned in the 2020 Energy White Paper[4]. Regulation does not exist separate to policy. If the Government's preference is to increase and decentralise the deployment of cost-effective renewables and flexibility as a key element of achieving the net-zero target, regulatory processes and the charging regime must not constrain this.

The UK has diverse renewable resources that can be deployed across the whole country, with one of the best potentials for onshore and offshore wind. Energy diversification is important to provide energy security and long-term sustainability transitions. The UK has a strong economy and so requires a variety of energy sources for industrial production, electricity production, transport, and domestic use. The proposal from Ofgem is not taking into account the benefits of a diverse energy mix and the implications that not considering this could have on security of supply.

4. Planning regime across the country

Today, the planning and consenting system for onshore wind developers is more favourable in Scotland than in England and Wales. While the Scottish Government's Onshore Wind Policy Statement[5] reaffirms commitment to enable the development of onshore wind in the country, the current planning regime in England has been shown to be more challenging and hostile to the deployment of onshore wind. This is concerning as the FES consumer transformation scenario from National Grid (the main scenario used by Ofgem in its analysis) shows that we will need embedded onshore wind generation across the whole country. Thus, locational charges are at odds with other policy levers, and thus do not act as the incentive they are designed to be, but instead become market distorting. Ofgem needs to consider the wider policy environment, including delivering net zero in its charging design.

Additionally, we can see that the southern North Sea is becoming increasingly congested, with offshore wind projects seeking space to operate alongside many other users. Similarly, solar energy for large sites in the south of England is becoming progressively difficult to find. Overall, we can see how Scotland's renewable resource will become gradually more important to supply the energy we will need to meet our climate targets. Therefore, this is an important variable that Ofgem must consider in its analysis.

5. The impact on repowering decisions.

The model has not sufficiently identified the impact on repowering decisions. Currently, Scotland has 60% of the UK's onshore wind capacity and by 2035 many operational projects will reach the end of their consented period, requiring reconsenting and repowering with the latest turbines in areas that are proven to be suitable for renewable generation. Repowering and new sites will both be needed to achieve net zero.

In the consultation document, Ofgem recognises there is a risk that if existing generators facing significant increases in TNUoS charges (up to £30/kW) choose not to repower and alternative generators are not able to internalise the impact, then some network assets built to provide capacity will become stranded. Today, generators already face TNUoS charges of almost £30/KW, which will increase significantly if code modifications CMP317 and CMP 374 progress unfavourably. This is concerning because the 'quantitative analysis of Ofgem options' also illustrates that over the period between 2024 and 2040, distribution-connected onshore wind will have losses of -369 and -226.4 £/kW (in terms of NPV) in the north and south of Scotland respectively. This will clearly threaten any repowering decisions. Also, this further highlights the issues associated with modelling which treats generation capacity as an exogenous input.

6. Increased risk profile for developers

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[4] https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
[5] https://www.gov.scot/publications/onshore-wind-policy-statement-9781788515283/

If TNUoS charges are applied to SDG, new renewable projects can account for higher TNUoS costs in their CfD bid, but existing renewable projects will not be able to absorb the impact in the same way, which increases the risk profile for developers, risk that is intensified with the greater regulatory uncertainty of such structural changes to TNUoS. Furthermore, it is important to highlight that customers do not end up obtaining a saving unless projects move location (because lower demand TNUoS is modelled as being offset by more expensive CfD support) and are more likely to incur a net increase in cost as a result of an increased risk premium falling on generation due to greater regulatory uncertainty.

We think that if Ofgem is going to reform TNUoS they should carefully consider the impact of change on operational projects (or projects in late-stage development). We believe that some form of grandfathering would be needed to reasonably mitigate this impact.

7. TNUoS reforming timeline

Today, transmission-connected generators are already impacted by high TNUoS charges, hence a quick fix is needed to unlock this consented generation so investment can take place and sites can be constructed. The timeline that this reform could take creates ongoing uncertainty for developers and their investors, putting at risk the opportunity to deliver net zero at least cost. We believe that, in parallel, it will be essential to implement “quick fixes” which mitigate the mistakenly oversized locational signal in the immediate term, while TNUoS reform is being considered, to avoid sending the UK off-track from the deployment scale needed for a low-cost net zero pathway. Without such fixes, consumers will have to bear the additional costs of onerous delayed corrective action.

Experience indicates that code reviews take a minimum of five years. As significant progress will have to be made in decarbonising the energy sector by 2030, timeframes of five years or more to implement regulatory change in an environment where key targets need to be achieved in eight years’ time is untenable.

**General question**

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

First, we believe that Ofgem can make TNUoS savings through increased competition for TOs and DNOs by increasing the number of parties that can deliver works across each region. This will reduce costs and improve programme timelines. Some DNOs are repeatedly given unjustifiably long programmes and high connection charges for their projects, and this won’t change while TOs have a monopoly on the connection offer process. Therefore, we would like this solution to be considered in Ofgem proposals.

Second, we would like to highlight the key reasons why the current TNUoS regime is not fit for purpose and why urgent action is needed to change it. Overall, we believe that regulation should move forward at a pace to facilitate the deliveries of government commitments, and it should not constrain those in any case.

1. TNUoS no longer does what it was designed to do

Back in 1992, the charging system was designed to provide clear signals to the energy market to incentivise developers to build fossil fuel power stations close to demand. Today, as we move to a smart, decentralised and more decarbonised energy system, a fairer system which balances the strengths of different parts of the UK is needed.

The renewables industry has led rapid cost reduction over the last decade, with developers reducing the costs at every stage from finance and procurement to design and delivery. However, TNUoS is a cost that developers cannot control. This means that as the cost of a unit of renewable electricity has come down, the proportion of that cost represented by TNUoS has gone up significantly. This is in combination with a predicted substantial rise in transmission charges over the next five years, with the differential between northern and southern projects also amplifying. According to a recent report by SSEN Transmission, a wind farm in the north of Scotland currently pays £5.50 per unit of energy as part of the locational TNUoS charges compared to an equivalent wind farm in Wales getting paid £2.80 per unit[6]. This increased cost that TNUoS imposes makes Scottish projects less competitive, encouraging generators to install projects in the south of the UK without considering where the best renewable resources are located to deliver the lowest cost pathway to achieving net zero. This system does not match the decentralised, smart and decarbonised energy system of the future.

A recent report by RIDG[7] showed that the UK has among the highest locational charges in Europe; indeed one of the few countries that charges a locational element for transmission charges. This is putting UK generators in Scotland at a disadvantage to European generators. As we become more interconnected with Europe, the TNUoS methodology is incentivising the system operator to import (potentially more carbon intensive) power over the interconnectors, at the cost of lower deployment of renewable generation in GB, and increasing reliance on the interconnectors for security of supply.

2. TNUoS volatility is affecting consumer bills

TNUoS volatility increases the cost of capital of projects, and given the scale of investment in wind generation expected in the next years to meet the Government's climate targets, this additional cost will ultimately be placed onto energy consumers to pay.

Along with amplified locational signals, volatile and unpredictable TNUoS charges are also harming renewable investment. In research conducted by SSEN Transmission they found:

- Generators see swings in their TNUoS charges typically over 50% up or down each year.
- Charges are unpredictable – Using National Grid's own data, the average forecast error under-estimated the actual charge by one third.

This volatility is in sharp contrast to the total revenue allowed of the TOs that TNUoS charges are set to recover. The cumulative allowed revenue of NGET, SPEN and SSEN Transmission has been stable, within 5% of £2.5 billion, over the past five years. Investors need cost certainty and clear, forecastable TNUoS when planning and delivering long-term investments at lowest cost of the UK consumer. We also note that price volatility is a significant challenge for operational sites, where projects have been built and financed at a specific point in time based on the best view of TNUoS. Once final investment decision has been taken, these projects cannot react to changes in locational signals and therefore volatility in TNUoS costs simply adds risk to the projects. Volatility and unpredictability are not unique to Scotland but experienced by all generators regardless of technology or location. This uncertainty leads to increasing risk margins for developers, ultimately increasing costs that will be passed onto consumers.

3. TNUoS is not aligned with net zero

The current TNUoS regime is not fit for purpose to meet either the Scottish Government or UK Government's net zero climate targets. The way that TNUoS is designed encourages generators to locate

[6] https://www.ssen-transmission.co.uk/news-views/articles/2021/2/ssen-transmission-calls-for-reform-of-unfair-and-volatile-charging-regime/
[7] https://cdn.ymaws.com/www.renewableuk.com/resource/resmgr/210524_tnuos_paper_final_for.pdf

close to the demand. This was appropriate for a fossil fuel-based system but now leads to disproportional charges by location as we move to a renewables-based system.

The transmission charging methodology is a complex combination of factors that must now include the need to deliver net zero alongside other electricity system and policy goals. Without a rethink, we believe that the direction of travel in network charging could result in a major barrier to delivering net zero. As discussed previously, there is a strong case to review the transmission charging methodology to ensure that the development of renewables is not discouraged where resources are most abundant. The need for review is even more pronounced given the ongoing review and reform of the offshore transmission arrangements.

To achieve our respective net zero targets, we will need a steep increase in renewable energy installation by 2050 in all parts of the UK, not just the south. According to the Sixth Carbon Budget from the CCC, the renewable deployment by 2050 should be between 95GW and 125GW of offshore wind, between 75GW and 85GW of solar PV, and between 30GW and 35GW of onshore wind. Scotland has the resources to supply a big proportion of this deployment, but with TNUoS disadvantaging Scottish projects in the CfD, there is a risk these projects may not be built, reducing our ability to reach net zero. It is important to move forward at pace with a strategic review about how best to use regulation to allow a proportional deployment of renewable energy across the whole UK.

4. TNUoS is harming Scotland's economy

The extra cost of paying electricity transmission charges makes Scottish projects less competitive in the CfD auction process. 1GW of renewable electricity generation means £133 million to the Scottish economy, therefore fewer projects mean the money which the private sector must invest to meet net zero will be spent elsewhere in the UK. This can be reflected in auction round AR1[8], AR2[9] and AR3[10] available through BEIS website (see table below), which shows that the capacity awarded to offshore wind Scottish projects[11] has decreased from 39 % in AR1 to 9% in AR3.

| **Auction Round** | **Total offshore wind capacity awarded (MW)** | **Capacity of offshore wind Scottish projects (MW)** | **% Capacity awarded to Scottish projects** |
|---|---:|---:|---:|
| AR1 | 1162 | 448 | **39%** |
| AR2 | 3196 | 950 | **30%** |
| AR3 | 5466 | 466 | **9%** |

With respect to AR3 we would like to note that several Scottish projects failed to win contracts, the 90-turbine Moray West Offshore Wind Farm (sister project to the Moray East wind project) was unsuccessful in its CfD auction proposal, as was Red Rock Power's Inch Cape Wind Farm off the Angus coast. Several other remote island wind projects also failed in their bids, such as the Viking Wind Farm joint venture between the Shetland community and SSE.

This situation is expected to get worse without any action to the current TNUoS regime. According to National Grid ESO tariffs[12], the TNUoS charges in Scotland have increased from 11 £/kW from 2016 to

[8] Contracts for Difference (CFD) Allocation Round One Outcome - GOV.UK (www.gov.uk)
[9] Contracts for Difference (CFD) Second Allocation Round Results - GOV.UK (www.gov.uk)
[10] Contracts for Difference (CfD) Allocation Round 3: results - GOV.UK (www.gov.uk)
[11] CfD continues to support both new offshore and onshore projects however pot one technologies (those which are more established: Solar PV and Onshore wind) were not able to enter the auctions between 2015 and 2019. Therefore, this analysis includes offshore wind only.
[12] https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges

26.35 £/kW in 2021 and members of Scottish Renewables who are been doing their own analysis predict that the situation will get worse without any action.