Via email: FutureChargingandAccess@ofgem.gov.uk

Email: Tom.Steward@RWE.com

1st September 2021

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

Dear Patrick,

RWE Renewables is one of the world's leading renewable energy companies. With around 3,500 employees, the company has onshore and offshore wind farms, photovoltaic plants and battery storage facilities with a combined capacity of approximately 9 gigawatts. RWE Renewables is driving the expansion of renewable energy in more than 20 countries on five continents. From 2020 until 2022, RWE Renewables targets to invest €5 billion net in renewable energy and to grow its renewables portfolio to 13 gigawatts of net capacity. Beyond this, the company plans to further grow in wind and solar power. The focus is on the Americas, the core markets in Europe and the Asia-Pacific region.

Thank you for the opportunity to respond to the above consultation. Below we set out some key points, and detailed responses to the questions follow.

Key Points:

1. We strongly welcome the explicit inclusion of delivery of Net Zero as part of the decision-making criteria under the first guiding principle.

2. In the future, renewable generation will form the backbone of the energy system. It is essential that the network charging regime is a facilitator, not a barrier, to delivering this future efficiently.

3. RWE strongly supports OFGEM's proposal to undertake a review of the wider TNUoS methodology. It is not clear if the current charging regime is the right one to deliver an economically efficient transition to net-zero – RWE would welcome a meaningful, strategic, and forward-looking review of charging in pursuit of this objective, to be delivered as soon as feasibly possible.

4. The proposal to defer implementation of TNUoS charges for embedded generators offers the opportunity to ensure that only appropriate charges be levied on these generators. To do otherwise would risk imposing charges that

are later proven to be inconsistent with delivery of net-zero, on plant that are essential for its delivery.

5. The charging of TNUoS on SDG is likely to render a number of renewable development sites uneconomic. This will have significant carbon emission implications which were not considered in the impact assessment.

6. There are likely to be similar implications for existing sites that could otherwise have received life extensions, or been repowered. The impact on carbon emissions of these sites was also not considered in the impact assessment.

7. Grandfathering of charges for those generators that are negatively impacted by the proposed change would help to protect investor confidence. It is important that the eligibility for grandfathering is determined appropriately so that project development and investment to continues through the TNUoS review period. It is important to note that significant investment is made long before a site is commissioned.

8. On the connection boundary – it is very difficult to offer informed opinions on the likely effectiveness of the proposed changes to the connection boundary without also having the detailed proposals for the future of DUoS charging. These two aspects of charging are intimately linked. However, the proposal to maintain a different connection boundary for generators at distribution maintains an uneven playing-field between voltage levels.

9. On Access rights – a critical issue for distribution-connected generators is the lack of financially firm access arrangements. We note that current proposals require distribution connected generators to either meet the costs of mitigating network constraints themselves or to reduce their output. On the transmission system, costs of constraints are socialised via BSUoS. This maintains an uneven playing field between distribution and transmission-connected generators – in effect creating an "embedded disbenefit".

10. We have significant concerns that the shortcomings in the modelling mean that it is not possible for OFGEM to make an informed assessment regarding if the "Arrangements support decarbonisation and contribute to meeting net zero targets" – a central part of the first guiding principle of the SCR.

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Questions

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.

It is very difficult to take a view on if this is appropriate without a clear view of the aggregate locational signal that may exist in DUoS going forward. What is apparent however, is that this would maintain an uneven playing-field in connection charges between generators connecting at transmission (who face a shallow connection charge) and distribution, who under these proposals would continue to face a deeper connection charge than their transmission-connected counterparts. This appears to fall short of the first guiding principle of the SCR to deliver a level playing field between different voltage levels.

We propose that full shallow connection charging should be extended to distribution-connected generators, providing user commitments, akin to those in transmission, are extended to the distribution level. This will help to minimise the risk that abortive costs should need to be socialised.

It has been implied that the direction of travel for DUoS reform is towards a greater level of locational granularity – creating a stronger locational signal. A shallow-ish connection charge creates another, and potentially conflicting, locational signal. If indeed this is the intention for DUoS, the economic rationale for having two different locational signals is unclear.

Grandfathering arrangements should also be considered for generators who have paid up front for the reinforcement of the network under deeper connection charges, but who may now see their DUoS charges begin to increase as shallower connection charges lead to reinforcement costs being socialised in future, as new connectees join the network.

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?

It is clear the current arrangements do contribute to siting decisions for new plant. However, we are not aware of any reviews that have been carried out to establish if this leads to outcomes which are consistent with delivery of economically efficient net-zero. The forthcoming reforms to DUoS will interact with connection charges with regard to impact on where generation sites are developed, however it is difficult to assess the overall impact without having more detail on the nature of the proposed changes to DUoS.

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?

The degree to which this drives efficient development of the network will be affected by the level of risk that the DNOs face in relation to such an investment. It is not clear that DNOs would in fact have to fund more of the work over the long term – it is simply that they may face more of the cost up front, which they are able to recover later through DUoS bills. The DNOs will face financing costs in the intervening period, but it may be assumed that these are also recovered in full through DUoS. Ensuring efficient investment in network assets is outside of the scope of this SCR, as it sits within the RIIO framework.

However, it is possible that shallower connection charging could lead to a more economically efficient system overall. DNOs are typically large organisations with robust balance sheets, able to borrow at a very low cost of capital – much lower than some smaller generation developers. Therefore, requiring smaller up-front costs that are then paid for through DUoS bills is likely to be consistent minimisation of total system cost. However (as noted above), it is important that new connectees are required to commit financially, in order to ensure abortive costs are not socialised and deter speculative applications from less financially robust developers. This would also help to maintain a level playing field with those connecting to the transmission network.

Continuing to have a shallower connection boundary at transmission than distribution however maintains and “embedded disbenefit” and therefore risks driving inefficient investment decisions by generators.

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 for investment, as greater price certainty leads to lower cost of delivery (and cost of capital), and therefore lower consumer bills. It would be inappropriate to introduce unnecessary risk onto developers in order to support flexibility providers.

DNOs should already be seeking the cheapest option to facilitate connections and offer connection agreements on that basis. In some instances that will mean expanded network capacity, in others that could imply the provision of flexibility services – subject to the specifics of the network in the local area.

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?

Under the current regime, we are unaware of any compelling arguments to remove the high-cost cap. However, moving to a shallow connection boundary for embedded generation could potentially remove the need for it.

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?

It is important that such costs are treated consistently with where transmission-connected generators trigger reinforcement across all areas of GB. Currently Scottish Connectees are significantly disadvantaged 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.

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?

It is unclear how the changes to the voltage rule proposed would on their own increase the risk of cancelled investment. However, the combination with some reforms of DUoS could indeed lead to investments being abandoned. It is impossible to assess properly without a full view of the future of distribution charging. If the generation connection boundary at the distribution level were harmonised with transmission to create a level playing field, then there is an argument for introducing such liabilities.

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?

Some generators will have invested to expand the network, and under the current arrangements would benefit if a later-coming connectee took advantage of this expanded capacity. However, moving to a shallower connection boundary could mean that the investing generator will now lose out. These interactions need to be carefully considered to ensure that those that have already connected are not disadvantaged. This issue could be assessed alongside the introduction to the change to the connection boundary, in the same way that protecting those generators that have paid a deeper connection charge but will potentially now face increasing DUoS charges are the result of a shallower connection boundary.

4. Access rights

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?

There may be some value to a standardised range of non-firm access choices. However not including financially firm connection arrangements preserves an imbalance between transmission and distributed generation. This appears to fail to deliver on the first guiding principle of the SCR. This is particularly pertinent given the proposal that SDG are charged TNUoS on the same basis as transmission-connected generators, yet would do so on very different connection arrangements. We would urge OFGEM to set out a timeline for when this aspect of access rights will be reviewed and suggest that this should be completed ahead of introduction of TNUoS charges for SDG.

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?

As above, it is inappropriate for embedded generators to face non-financially firm connection arrangements, given the difference this creates from transmission-connected generators - full network access should be available to all, and the cost and/or impact of constraints on a generator should be socialised as they are on the transmission network.

In absence of this, it would not be appropriate to expose distribution connected generators with limited network access to the full wider TNUoS charge – this is a clear omission from proposals as they stand.

It is unclear how time-profiled access rights will be reflected in a generators DUoS charges. It is important that the two areas of charging tesselate appropriately to deliver optimal connection and dispatch decisions.

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

Throughout the Network Access workstream, the shared access right proposal included limited detail. Further information is necessary to understand how shared access rights could operate in practice, both from a generator's point of view, and in terms of reducing reinforcement costs (in a way that is not achieved through the other non-firm access arrangements currently being explored).

Shared access rights are unlikely to fully mitigate the costs of constraints to generators, since it is it is probable that any pair of generators will at some point want access to network capacity at the same time. We anticipate that the periods of overlap between generators wanting access could be significant – dependent on technology, and therefore will contribute towards making these types of projects uneconomic compared with equivalent transmission connected generators who benefit from financially firm access.

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)?

If generators are to face non-firm access arrangements, it would be logical for this to manifest not only in lower connection charges, but lower DUoS, and TNUoS charges too. However, it is impossible to suggest how such a proposal might work in practice without a clear view of the future of DUoS charges. It would be inappropriate to charge TNUoS to a generator that does not have a firm (physically or financially) connection to the distribution network, and therefore by extension, has no firm connection to the transmission network. This would be iniquitous with transmission-connected generation.

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 view.

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

DNOs should be required to offer a minimum range of flexible connection options, however this should not preclude their innovating with new options that might then become standardised in future. We would propose that OFGEM carries out a regular assessment of best practice to establish what new options that DNOs are developing that might then be considered for addition to the “standard” list.

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

1st April 2023 seems a realistic timescale for introduction of the access rights proposals from a generator’s perspective.

5. TNUoS charges for SDG

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?

As per question 4a, it would be inconsistent to charge SDG TNUoS when they do not benefit from the same financially firm access arrangements as their transmission-connected counterparts.

Although in the capacity registers generators have GSPs assigned, it is not clear that their output will consistently flow to that particular GSP (e.g. under different operational situations). Where the flow from an embedded generator could be said to flow into one generation zone or another, this could have a significant impact on the costs that a generator will face. Therefore, there remain questions of practicality for assigning which TNUoS zone some embedded generators may be said to be connected to.

The proposal for sub-1MW generation to face an uncapped EET places a perverse incentive for sub-1MW generators in positive TNUoS zones to cease export at Triad – this is economically irrational and will place additional strain on the network (as set out in the CEPA analysis). The CEPA analysis suggests this effect reduces over time with greater uptake of smart demand-side technology but does not explain why there is such a dramatic increase in take-up of these technologies under the reform proposals, but not in the baseline. It also appears that this level of load-shifting is built on assumptions of the existing DUoS methodology continuing – the robustness of this modelling cannot therefore be properly assessed without OFGEM’s decision on DUoS also being set out and considered alongside these proposals.

Currently there is not an equivalent metric to TEC for SDG. It is essential that a loss-adjusted equivalent, that generators are able to nominate and optimise in the same way as TEC, is put in place.

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?

A 10MW threshold could give greater consistency with other areas of network regulation, eg. classification and data requirements within the grid code, and better support non-traditional investors such as community groups who may be less able to engage with changes in the energy policy landscape such as this.

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

No view.

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 that this should not be solved as part of this consultation, but addressed separately in a more focussed way with careful considerations of impact on remote island wind sites and delivery of 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?

RWE strongly supports OFGEM's proposal to undertake a review of the wider TNUoS methodology. It is not clear if the current charging regime is the right one to deliver an economically efficient transition to net-zero – RWE would welcome a meaningful, strategic, and forward-looking review of charging in pursuit of this objective, to be delivered as soon as feasibly possible.

The proposal to delay implementation of TNUoS charges for embedded generators offers the opportunity to ensure that only appropriate charges be levied on these generators. To do otherwise would risk imposing charges that are later proven to be inconsistent with delivery of net-zero on plant that are essential for its delivery.

Grandfathering of charges for those generators that are negatively impacted by the proposed change would help to protect investor confidence. If applied appropriately – to projects that have already make significant progress towards delivery, grandfathering could ensure that projects to continue to come online throughout the TNUoS review period, and minimise the risk of hiatus in development.

The charging of TNUoS on SDG is likely to render a number of renewable development sites uneconomic. This will have significant carbon emission implications which were not considered in the impact assessment. There are likely to be similar implications for existing sites that could otherwise have received life extensions, or been repowered. The impact on carbon emissions of these sites was also not considered in the impact assessment.

Grandfathering is also essential to ensure economic efficiency. Where development sites are rendered uneconomic, costs will have to be incurred again by developers responding to the economic signal of halting active developments and beginning again with equivalent new sites elsewhere.

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, represents a substantive change in the framework under which they invested. Such substantial changes in the regulatory regime, without grandfathering, could have significant implications for investor confidence and cost of capital – something that was not captured in the modelling, but would undoubtedly have cost implications for end consumers. Transitional arrangements could help to mitigate these risks however.

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?

Of the options proposed, option one – based on the current method of delivering the EET appears to be the most practical, with least administrative burden, therefore leading to least financial cost. This approach is already known to generators and suppliers, and will not necessitate the ESO creating new contractual arrangements with the thousands of generators across the country (as proposed in option two). This option should however also be expanded to include aggregators.

Option three does not appear to be a beneficial variation to this approach, as aggregating generators together in the way proposed will reduce the transparency within billing.

Option four will also necessitate the creation of significant numbers of contractual arrangements, therefore is likely to carry significant unnecessary cost.

We are not aware of any alternative arrangements that would lead to better outcomes for generators, customers, or the wider system.

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?

Although the inclusion of consideration of consistency with delivery of Net Zero is very welcome, consideration of compatibility of the TNUoS reforms with the UK meeting Net Zero by 2050, or Scotland reaching Net Zero by 2045 is not strongly evident – particularly given the shortcomings in the quantitative analysis (set out below). Given the significant impacts that network charging will have on development, consistency with Net Zero should form a central consideration when assessing all policy decisions in this area.

We believe more clarity on the interaction with the proposals to charge TNUoS on SDG and other areas of policy is necessary. Most crucially, interaction with the €2.50/MWh cap under EU Regulation 838/2010, requires greater investigation (as set out below). This is further exacerbated by a lack of clarity in the minded-to document about the future treatment of the AGIC[1] - this has significant implications for revenues of embedded generators specifically, but also has potential interactions with the €2.50/MWh cap. The treatment of grandfathering of TNUoS charges within the cap calculation will also require consideration. These interactions will have a material impact on generators' future costs and revenues, and therefore must be set out in order to enable the full implications to be properly assessed.

7. 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?

We have several concerns relating to the modelling that was carried out to support the decision-making. Whilst we acknowledge that the decision is not made on the basis of modelling alone, it is important that all information that contributes to such an impactful policy decision is robust.

These proposals, if implemented, will have a significant impact on the future generation mix. Therefore, the treatment of generation capacity as an exogenous factor is a significant shortcoming of the CEPA-TNEI modelling – something CEPA themselves acknowledge.

This impact is not only limited to development sites however, but also the re-powering of existing sites. CEPA states that...

[1] Avoided GSP Infrastructure Credit

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…while we do not have direct evidence of the costs of re-powering, Renewable UK suggests that this may allow for somewhere in the region of a 20% saving on LCOE compared to investment in new capacity. In the case of repowering decisions in north Scotland, the net revenue impacts that we observe could represent up to 26% of LCOE for a repowering decision for an embedded onshore wind generator such that this could lead to a decision not to re-power for some projects. (CEPA Analysis, p42)

Repowering offers the opportunity to generate more power, on existing sites, from fewer turbines, at a cost below that of a new site. It is therefore not clear why thorough modelling of the capacity implications of a fall in the level of repowering has not been carried out.

The lack of consideration of changing technology mix also fails to capture the impact of geographical diversity on balancing costs, capture prices, and possible changes in installed capacity of flexible technologies – all of which could have significant impacts on overall system cost.

The modelling includes a lack of sensitivity analysis to take account of the current wider policy regime. For example, the model shows large amounts of onshore wind is deployed in England, where it currently faces significant planning barriers. Although the FES also makes assumptions about onshore wind deployment in England, OFGEM's proposed reforms are shown to further increase the requirement of build-out of onshore wind in England. This is likely to have an impact on low-carbon support costs, and transmission network development requirements. Without sensitivity analysis, the impact of the interaction between policies cannot be assessed.

CEPA states that "In the modelling itself, we do not allow for capacity to re-allocate between the transmission network and the distribution network". Instead relying on revenue modelling to give some insight. Given the express purpose of charging TNUoS on SDG is to drive more efficient decision-making about connecting to either the transmission or distribution network, failure to explicitly model a response to this appears to be a significant shortcoming.

The impact assessment makes the assumption that SDG TNUoS costs will be included in the calculation of the €2.50/MWh cap, however this appears inconsistent with the direction of travel of this policy area. Given the significant impact this will have on tariffs for different network users, the lack of sensitivity analysis in the IA is a significant shortcoming.

Limited attention has been paid to carbon emissions impact of these proposals – limited only to the effects of redispatch. It is not clear that the reduction in capacity factors owing to renewable generation being deployed in less resource-rich locations has been taken into account. Also, without the ability to reselect an alternative generation mix, the impact of the inevitable trade-off between onshore wind (typical capacity factor 34%) and solar (typical capacity factor 11%) has not been considered. A limited focus on carbon emissions such as this means it is also not possible to assess the impact of this change on the energy sector's contribution to meeting the carbon budgets. Any reduction in contribution would require greater carbon savings to be found in other areas of the economy, potentially at higher cost.

In summary, we have significant concerns that the shortcomings in the modelling mean that it is not possible for OFGEM to make an informed assessment regarding if the "Arrangements support decarbonisation and contribute to meeting net zero targets" – a central part of the first guiding principle of the SCR.

<u>Timings</u>
While RWE supports the timing of changes to the connection boundary and access arrangements, as set out in the minded-to decision, there remains a great deal of uncertainty as the analysis on DUoS reforms, as yet to be published to industry.

It is our understanding that Ofgem intends to publish and implement the two Network Access SCR decisions together. While some of the changes being consulted on now could be implemented by 2023, it would be unviable to seek to introduce SDG TNUoS, even with transitional arrangements, from this date. We propose that 2025 is the earliest viable date for introduction of these changes – before which time the following steps must be taken:

- Consideration of Phase 1 consultation responses
- Launch of phase 2 consultation
- Consideration of phase 2 consultation
- Publication of decision
- Multiple code modifications launched and progressed through multiple codes

This final step is of particular concern – there are a number of other critical changes live in the industry at the moment, and there is only so much industry capacity to progress code changes to delivery.

<u>Stakeholder engagement</u>
Having engaged with many stakeholders across industry, following the publication of this consultation, it is clear that there are a significant number of questions that remain unanswered – particularly with regard to the modelling that has been carried out. It is disappointing therefore that OFGEM chose not to meet its commitment in the minded-to decision document and hold both a Charging Futures Forum, and a Challenge Group session during the consultation period. This both removed the opportunity for stakeholders to ask questions to shed light on the areas of the consultation that are less clear, and to work with OFGEM to help deliver the best possible outcomes for consumers on the path to Net Zero. We note that OFGEM are not obliged to hold stakeholder engagement events in relation to consultations, however given the regular events that have been held throughout this workstream, this represents a departure from previous practice at a critical point in the development process.

I hope that you have found this response useful. If you have any questions, please do not hesitate to contact me.

Yours faithfully,

Dr. Tom Steward

Senior Regulatory Affairs Manager
RWE Renewables