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21 February 2022

To whom it may concern,

**Access and Forward-looking Charges Significant Code Review: Consultation on Updates to Minded to Positions and Response to June 2021 Consultation Feedback**

Scottish Renewables is the voice of Scotland's renewable energy industry. The sectors we represent deliver investment, jobs, social benefits and reduce the carbon emissions which cause climate change. Our members work across all renewable energy technologies, in Scotland, the UK, Europe and around the world. In representing them, we aim to lead and inform the debate on how the growth of renewable energy can help sustainably heat and power Scotland's homes and businesses.

We have responded to your individual consultation questions further below, but in summary, we would like to draw your attention to the following points:

- We welcome that the section regarding TNUoS has been removed from this consultation, and the decision about extending TNUoS charges to Small Distribution Generators (SDG) has been delayed subject to the results of the recent call for evidence.
- We think that the new phased approach on DUoS and the review of TNUoS charges provide Ofgem with the opportunity for reviewing the quantitative analysis of the Access SCR from June 2021, and updating it before confirming the implementation of TNUoS charges for SDG. We think there is a strong case to review the net benefit impact of the Access SCR, which may change the overall outcome of the proposal.
- Policy proposals from the Access SCR linked with DUoS reform must be reviewed carefully in order to avoid slowing down the roll-out of low carbon and flexible technologies.
- We agree with introducing a HCC for demand, and retaining one for generation. However, it is difficult to assess the net outcome of this proposal without knowing what will happen with DUoS.
- Scottish Renewables thinks there is a case for compensating projects that have paid for expanding capacity and are now subject to DUoS as well. We believe it is unfair to charge generators twice. In the past, when we moved from deep to shallowish distribution connection charges, there was recognition that generators should not pay for reinforcement twice, leading to a DUoS exemption.
- We think that embedded generators need to be able to predict when curtailment is likely to happen. Therefore, we recommend that instead of measuring curtailment by % time per year, it would be better to measure this seasonally, for example the number of hours per season (understanding season as winter, summer, spring, and autumn).

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- Scottish Renewables disagree with excluding customer interruptions and transmission constraints from the definition of curtailment. Excluding customer interruptions from the definition of curtailment will lead generators to face continuous unjustified and unquantified risks. Similarly, excluding transmission constraints will lead to increased risks for generators.
- We also disagree with Ofgem's proposal of not introducing a cap for flexibility payments made that exceed agreed curtailment limits. A cap should be introduced on payments made by DNOs who exceed agreed curtailment limits - there is no value to the network user if an agreed curtailment limit is breached by the DNO and there is no penalty/compensation tied to this.

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

Yours sincerely,

A handwritten signature in black ink, appearing to read 'Angeles Sandoval', with a long horizontal flourish underneath.

Angeles Sandoval  
**Policy Manager | Networks & Markets**  
Scottish Renewables

## 1. Distribution connection charging boundary

### Question 1.1:

- I. **Do you believe that it is necessary to introduce a High Cost Cap (HCC) for demand, and to retain one for generation?**

As the current proposal stands, Scottish Renewables agrees with introducing a HCC for demand, and retaining one for generation, assuming that no significant changes are made to DUoS. However, if the reform of DUoS results in a very granular DUoS, this proposal needs to be reconsidered, as the value of a HCC becomes very difficult to assess.

- II. **Do you believe that our proposals to do so represent sufficient and proportionate protection for DUoS billpayers against excessively expensive connections driven reinforcement?**

No comments.

- III. **What are your views on retaining the current 'voltage rule' to determine whether the HCC is breached (ie considering the cost of reinforcement at the voltage level at point of connection and the voltage level above)?**

Understanding that connecting customers will still face reduced reinforcement charges versus status quo arrangements, regardless of whether they hit the cap, we support the principle behind this proposal.

In Ofgem's webinar on February 4, 2022, Ofgem stated that generators will contribute to reinforcement at the point of connection only, and any reinforcement at the voltage level above will be fully funded by DUoS billpayers. On the other hand, for the case of demand, any reinforcement at connection voltage and connection voltage above will be fully funded by DUoS billpayers. Therefore, understanding that this is the principle behind this question, we agree with the proposal.

In addition, we think that a similar principle should be extended to transmission connections works triggered by a DNO at distribution. Transmission reinforcement should not fall entirely on users at lower voltage – future decisions on charging should strive for consistency on this issue.

- IV. **What are your views on the principles we have proposed to determine an appropriate HCC level for demand, including the potential for this to be set at a different level to generation under these principles?**

Scottish Renewables thinks that this proposal needs to be reviewed in more detail. It is still not clear why Ofgem decided not to index the cap. At the moment, the cap is a fixed threshold (£/kW or £/kV), which in real terms is a shrinking cap.

### **Question 1.2:**

**What are your views on our proposals to maintain the requirement for three phase connection requests to pay the full costs of reinforcement, in excess of Minimum Scheme (ie lowest overall capital cost)?**

No comments.

### **Question 1.3:**

- I. Do you agree with our proposals to maintain the current treatment of speculative connections and is there a need for further clarification on the definition of speculative connections?**

No comments.

- II. Do you agree that our wider connection boundary proposals broaden the disparity between connections deemed to be speculative versus non-speculative? If so, do you believe this needs to be addressed and how?**

No comments.

### **Question 1.4:**

**Do you consider that our proposed DUoS mitigations (a demand HCC, and retaining reinforcement payments for three phase and speculative connection contributions) present a cohesive package of protections for DUoS billpayers? Do you consider these proposals to interact in any way that could counter their effectiveness, and if so, how?**

No comments.

### **Question 1.5:**

**Do our updated proposals to treat storage in line with generation for the purposes of connection charging simplify charging arrangements for these sites and better align with the broader regulatory and legislative framework?**

This proposal seems simplistic considering the benefit that storage provides to the grid.

In the call for evidence on TNUoS last year, Ofgem suggested that further work in respect of charging arrangements for storage of all sizes may be warranted in the context of its potential to provide solutions to network issues rather than to act solely as a wholesale market participant. We agree that network charging is a key factor to consider in the policy regime for the development of storage. It will be important that the charging regime appropriately reflects the value that these flexible resources provide to the electricity system, both as demand and generation for transmission and distribution level.

A critical function of Large-Scale Long Duration Storage (LLES) at transmission is to provide balancing and stability services to the market and network. LLES are not net MWh generators, but they are defined as generators and therefore the balancing and stability benefits (and cost savings from

reduced network investment) are not reflected in the way their connection application to the grid is assessed. LLES is considered as just another generator and is connected on a first come first served basis behind other generators. Storage technologies can make a major contribution in facilitating a cost-effective transition to net-zero, by both enabling the rapid growth in variable wind and solar renewables and accelerating the displacement of fossil fuel generation<sup>1</sup>.

We consider that the flexibility and locational benefits of storage should specifically be taken into account in the design of charging arrangements, recognising and thereby incentivising the value that these assets provide at distribution and transmission levels.

**Question 1.6:**

**Do you agree with our proposals regarding the treatment of in-flight projects (ie that they should not be permitted to reset their connection agreement and retain their position in the queue), noting they retain the right to terminate and reapply from 1 April 2023 should they wish to be treated under the proposed connection charging boundary?**

Scottish Renewables agrees with this proposal. However, we would like to note that Ofgem is not including any compensation for projects that have paid for expanding capacity and that are now going to be subject to DUoS as well. We believe it is unfair to charge generators twice. In the past, when we moved from deep to shallowish distribution connection charges, there was recognition that generators should not pay for reinforcement twice, leading to a DUoS exemption. We believe this precedent should also apply in this situation.

**Question 1.7:**

**Do you agree with our proposals to retain the existing arrangements for managing interactive applications? Do you agree with our proposals on the treatment of unsuccessful applicants (that the connection charges at original application date will continue to apply if queue position is retained)?**

No comments

**Question 1.8:**

**Do you agree with continuing with the definition of the Minimum Scheme as currently set out in the CCCM? Do you believe this definition requires any further clarification or amendment, and if so, why?**

Scottish Renewables mostly agrees with the definition of the Minimum Scheme as currently set out in the Common Connection Charging Methodology (CCCM).

However, we think it is important to analyse how the Minimum Scheme in the CCCM could help to anticipate investment. In the past, any action needed has been set out when a connectee triggers a reinforcement, and it seems that Ofgem is not changing that way of working. We believe that with net-

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<sup>1</sup> Imperial College London. Whole-System Value of Long-Duration Energy Storage in a Net-Zero Emission Energy System for Great Britain. Available: <https://www.imperial.ac.uk/energy-futures-lab/reports/Whole-System-Value-of-Long-Duration-Energy-Storage-in-a-Net-Zero-Emission-Energy-System-for-Great-Britain/>

zero and all the electricity that will come from renewables by the 2030s, it is time to move on to a regulatory framework that helps to anticipate investment ahead of need.

**Question 1.9:**

**Are there any risks associated with our proposals to allow current non-firm connected customers to seek a firm connection following the changes proposed by our SCR? Do you agree that existing non-firm connected customers that do seek a firm connection should be processed through existing queue management processes as determined by DNOs?**

No comments.

**Question 1.10:**

**How necessary do you consider Ofgem intervention in Electricity Distribution Standard Licence Conditions 12, 15 and 15A? What duration might such measures be needed, or acceptable, following 1 April 2023? What value do you place on certainty of connection timeframes compared with time to connect?**

No comments.

## **2. Access rights**

**Question 2.1:**

**Do you agree with our proposal to exclude customer interruptions and transmission constraints from the definition of curtailment with respect to distribution network access arrangements?**

We disagree with excluding customer interruptions from the definition of curtailment. Excluding customer interruptions mean that the DNOs are taking no responsibility to do anything about it, and generators are continuing to face unjustified and unquantified risks.

We also disagree with excluding transmissions constraints from the definition of curtailment. Although Ofgem says that what happens with the transmission network is outside the DNO control, in our view, this is also outside the control of the generator. Therefore, it is unclear why the generator should take this risk.

Scottish Renewables believe that if Ofgem is thinking of extending TNUoS charges for Small Distributor Generators (SDG), this question must be reassessed once that policy is applied. If SDG generators must be exposed to the same level of charging as transmission connected generators, then they should be exposed to a similar level of risk as transmission connectees. This will lead to a level playing field between distribution and transmission.

**Question 2.2:**

**Do you agree that the curtailment limit should be offered by the network based on maximum network benefit and agreed with the connecting customer?**

Yes, we agree. A curtailment limit agreement is good for transparency, but also a more accurate recording of curtailment would be important, particularly for helping to quantify the signal for future network planning.

On the other hand, measuring curtailment by % time is unhelpful. We think that something more granular would provide more value for customers. Therefore, we recommend that instead of measuring the curtailment by % time per year, it would be better to measure this seasonally, for example the number of hours per season (understanding seasons as winter, summer, spring, and autumn).

Additionally, DNOs could give an indication of when in the day curtailment is likely. This is key for renewable generators such as solar PV, where curtailment at night is no problem, but curtailment in the middle of the day (when there is high solar output) has a serious impact.

**Question 2.3:**

**Do you have any views on the principles that should be applied to ensure curtailment limits are set in a consistent manner?**

No comments.

**Question 2.4:**

**Do you agree with our proposal not to introduce a cap for flexibility payments made should any curtailment in excess of agreed limits be required?**

We disagree with this proposal. A cap should be introduced on payments made by DNOs who exceed agreed curtailment limits. Flexible connections need greater visibility on the times they could be curtailed – there is no value to the network user if an agreed curtailment limit is breached by the DNO and there is no penalty/compensation attached to this. The RIIO-ED2 regulatory framework needs to be strengthened to allow for DNOs to procure against the need to exceed curtailment limits and incentivise accurate forecasting.

**Question 2.5:**

**Do you agree with our proposal to introduce explicit end-dates for non-firm arrangements? Are there any mitigations for DUoS billpayers we should consider?**

We think that there may be some difficulties with how this is applied and how the DNOs may use this to dump costs. The curtailment should be used as a proxy signal for where networking assessment is needed. A good approach would be to replicate the Network Options Assessment (NOA) process, where the DNO has the costs of curtailment, which could be balanced off with the costs of reinforcement. If DNOs are actively managing the system, this is how they should be doing it.

**Question 2.6:**

**Do you have views on whether the end-dates should take into account only current known or likely works, or if it should allow time for wider developments to take place?**

No comments.

**Question 2.7:**

**Do you have any comment on our proposal not to further define or standardise time-profiled access arrangements?**

No comments.

**3. General questions**

**Question 3.1:**

**Has the additional information in this consultation affected any of the views your previously submitted in response to our June 2021 consultation (if so, in what way)?**

**Question 3.2:**

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

**Response to Q3.1- 3.2**

We would like to highlight that it is positive to see that the section about TNUoS has been removed from this consultation, and the decision about extending TNUoS charges to SDG has been delayed subject to the results of the recent call for evidence.

On the other hand, we would like to raise our concern about the uncertainty that generators are experiencing with the different ongoing reforms, including the uncertainty around the lack of financially firm access arrangements to the transmission system, which is not in the scope of this reform.

Finally, Scottish Renewables thinks that it is important that before developing any further proposals, Ofgem reviews the quantitative analyses performed in the Access SCR last year. When we responded to that consultation in August last year, we highlighted that the quantitative analysis that assessed the option of applying TNUoS charges to SDG had significant flaws, which we felt needed to be addressed to gain comfort that there was an overall net benefit. We noted that in the analysis, Ofgem ignored many variables that a renewable planning system needs. Consequently, the proposal was based on a cost analysis that did not reflect the complexity of the energy planning network. The detail of this information can be seen in Annex 1.

We think that in light of the new phased approach on DUoS and the review of TNUoS charges, Ofgem needs to review the quantitative analysis of the recent Access SCR and update it before confirming the implementation of TNUoS charges for SDG. We think there is a strong case to review the net benefit impact of the Access SCR which may change the overall outcome of the proposal.

## ANNEX 1

### **Material flaws in the Quantitative Analysis when TNUoS is applied to SDG - Access and Forward-looking Charges Significant Code Review: Consultation on Minded to Positions**

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, 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 (page 29 of the CEPA-TNEI report) 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 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.