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Future Charging and Access Team
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18th August 2021

Dear Future Charging and Access Team,

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

Belltown Power UK Limited ("Belltown") is a developer of onshore wind, solar and storage projects in the UK with a pipeline of 1GW of UK renewable energy capacity in development. It is part of the Belltown Group that operates 200MW of subsidised UK renewables, as well as having operations in US Power and sustainable agriculture. The Belltown team has significant experience in the development, construction and operation of renewable energy generation assets in the UK. Belltown is an independent, privately owned enterprise. In responding to consultations we aim to be transparent, logical and unbiased, with the goal of using our valuable industry insider knowledge to support government and other public bodies in tackling the climate emergency as rapidly and efficiently as possible for society as a whole.

I hope that you will consider our response to this Consultation thoroughly, and I would be happy to be contacted if you have any follow-up questions or further information requests to support our positions.

Yours Sincerely

Paul Hewett
CEO, Belltown Power UK Limited
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3. 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 believe Ofgem should go further and move to a fully shallow boundary for generation, combined with a reform of DUoS to make it an ultra-long-run cost model, like TNUoS (but an improved TNUoS as is expected through the now envisaged wider TNUoS review). The current economic analysis presented seems to only take into account the cost to the ***network*** and not to the entire electricity system or even wider economy. There are costs associated with locating renewable energy generation in areas with lower natural resource, in that greater capacity needs to be built to meet demand. There are also costs associated with locating generation in areas of greater environmental and visual sensitivity, many of which are extremely difficult to quantify. Ofgem have stressed in challenge group sessions that the financial analysis is only one part of the evidence for deciding on changes. However, we would argue that the results for different options are so similar that they can be excluded from the decision making process entirely as the error bar in terms of actual value to the system, and hence consumers, is likely far larger than the small changes implied, and from a qualitative review is skewed towards deeper boundaries coming out as lower cost.

Given that all infrastructure has shelf-life and needs replacement eventually, anything other than an ultra-long-run ongoing charge approach to connection cost leads to a bias towards keeping the status quo, rather than building the system that will be cheapest in the future. If we are incentivising renewable generation to be located in areas with existing grid, we will just be creating a perpetual cycle of reinforcement of the existing, sub-optimal grid, rather than incentivising the creation of the most efficient grid for the long-term.

We as a developer would never apply for a grid connection in an area where upgrades would make the cost prohibitive. It is very easy to get this information for cheap or free from public data and informal pre-application conversations with DNOs and grid connection applications costs thousands of pounds. Therefore, Ofgem using accepted or rejected grid connection offers as the primary evidence for whether the depth of the boundary is actually making any difference to projects would lead to very inaccurate conclusions – if someone has applied for grid it is because they have already done enough work to determine that significant upgrades would not be triggered (or that they may be at a level that is viable for the project to fund).

A shallow boundary and an effective ultra-long-run DUoS model will incentivise the most efficient path to net zero and for the building of the system we need for the future, not the one that was best suited to our past. Moreover, making decisions on the connection boundary before making a decision on the DUoS charging regime does not make any sense. We understand the need for giving plenty of foresight to DNOs about the likelihood of change, but the two are so interlinked that Ofgem must be willing to rethink the connection boundary proposition in light of the DUoS charging decisions (which we hope will be coming soon!).

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 proposed changes will bring forward some new projects, where the reinforcements required happen to be at the voltage above. However, this just replaces one artificial distortion with another, different arbitrary rule – why does Ofgem want to encourage worse projects that happen to need reinforcement at a higher voltage level rather than better projects with reinforcement at their own voltage level? Ofgem should be removing all distortion unless there is a very good reason not to – in this case we do not see enough evidence to show why this distortion would not be removed entirely and a shallow boundary adopted (subject to appropriate DUoS charging methodology).

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?

Agree with Ofgem conclusions that not having reinforcement paid for by the triggering party, but by the DNO will help encourage the use of alternative technologies and business models that are more efficient than connection infrastructure upgrades.

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?

Generation customers deal with a huge deal of uncertainty (not least with respect to wholesale power pricing – regardless of whether the first 15 years are protected in a PPA or CfD). Therefore, saying that investors need price certainty is not true. Investors are just used to having price certainty on these specific connection costs. Over time a higher, ultra-long-run DUoS charging methodology will be just another variable that needs to be forecast and taken into account. It is true that investors may not be best placed to create accurate forecasts for grid charging – we expect it will be harder for non-DNOs to forecast DUoS charges than it is for example to forecast power prices. In order to encourage the lowest cost of capital it is most efficient to have the best information freely available. Therefore, allowing the network operators sufficient budget to engage quality market forecasters to produce long-term (e.g. 15 year) and freely available grid charging forecasts will lead to the most efficient outcomes that are possible (noting that given the uncertainty around the future, it cannot be expected that forecasts of grid charging will be wholly accurate over such a time period). In general, we expect that these inefficiencies will likely be more than offset by the efficiencies vs. the current system.

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?

The high cost cap is yet another arbitrary distortion (why £200k/MW?). In any case it will not be necessary in a fully shallow model.

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?

Yes, this needs to be considered. It is yet another distortion for one project vs. another. Such costs should be treated the same whether the project is distribution or transmission connected. We understand from your response that this is a more complex thing to change, but it is important that this is addressed and so would support that work being undertaken.

We are currently considering at least two distribution connected projects that would have to fund significant transmission infrastructure (with the potential of being paid some of this back in the future). Meanwhile we have other direct transmission connected projects that are triggering very similar works and which only have to secure their part of the works (and ultimately don't actually have to pay for those works except through shared TNUoS). Fundamentally the costs to the system are the same, but we are being incorrectly incentivised to progress the transmission connected projects over the distribution ones because of the distribution burden on us as the triggering party.

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?

Appropriate securities and queue management (i.e. must have applied for planning within [xx] or can be replaced by more advanced projects) are a good way of ensuring efficient development of solutions. These must be proportionate though, given that most upgrade work will be for the benefit of many future projects and uses and not just the applying party.

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. But note that the timing of implementation of the proposed reforms will be important. Introduction of a shallow boundary, or even a shallower boundary, will lead to lots of new application at 00:01 on 1st April 2023. It should be considered how these are prioritised/treated. We would suggest that, given that increases in DUoS caused by the move to shallower boundaries will also affect existing projects, that some effort is made to manage this (e.g. through grandfathering or reimbursement) to avoid the cliff-edge effect or significant double-charging.

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?

A simple "maximum % of curtailment" is not very helpful unless significantly more information can be provided about when this may be. For non-dispatchable assets like solar a simple % curtailment tells the project nothing as all of that curtailment may be during the night (with no impact on value) or all of it may be during the day (with high impact on value). Even for dispatchable technologies or wind (which has a more random generation profile), detailed information will need to be given for analysis of when such curtailment is likely to happen (historical power flows, etc.) for this to be in any way a bankable option for projects.

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?

Yes. This would be more useful than a % curtailment as the impact can be much more reliably assessed. Each technology has different time-based access needs and each network constraint also has specific characteristics. Therefore we would suggest flexibility in what the time profile is, so that developers and DNOs can work together to define the optimal access rights for the specific situation.

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

No. Agree that this is not likely to be taken up.

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?

No comments.

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?

No comments.

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?

No comments.

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 comments.

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?

No comments on the options, but disagree that this should not be addressed now as part of this reform (or the wider TNUoS reform that is now expected). The fact that there are limited examples of this at the moment does not detract from the fact that it is a distortion and will lead to inefficient behaviours. SDG connecting to the transmission system not at a MITS node should pay the same as TG in the same location.

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?

No comments.

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?

The current methodology for calculating TNUoS is completely flawed and needs to be overhauled. It is designed for the system of 30 years ago, which is completely different to the system that we will have in 30 years' time. We are undergoing an energy transition and all parts of the system need to transition – generation, demand and transport – and so Ofgem should not be afraid of making significant changes.

The actual cost drivers for the network need to be assessed and understood and then reflected in a new charging system. Generation and demand should be paying much more accurately for their actual contribution to the long-term cost of the system so that they have appropriate price signals to factor into their financial analysis. We have as yet not seen any work from anyone on what actually does drive the cost of electricity transmission in a net zero system and this needs to be completed as a priority in order to inform effective policy for the future.

For example, solar in Scotland is currently completely unviable due to the TNUoS it would face. That would be fine if those TNUoS costs were representative of the effect of that solar on network cost. However, the current simplified TNUoS methodology means that Scottish solar gets penalised for being in an un-diverse region despite the fact that it may actually help add diversity. A much more dynamic and representative cost allocation system needs to be developed as quickly as possible to ensure the most efficient energy transition.

When the TNUoS charging model was first introduced, computing power was a constraint in the development of the methodology. This is no longer the case, but the methodology has not been significantly upgraded to reflect this. A few observations: (i) only two grid flow scenarios are modelled ("peak" and "year round"). There is no reason why this shouldn't be expanded to reflect the actual diversity in grid supply / demand conditions. (ii) solar is still classed as "onshore wind", while battery storage is still classed as "pump storage". There is no reason why these should not have their own generation class with their own characteristics (iii) there is no category / methodology for co-located projects (iv) the "adjustment tariff" to ensure compliance with EUR 2.50/MWh cap rule is applied as a flat £/kW adjustment across all charging zones which reduces the locational signal. This introduces the same problem that the TCR sought to resolve. A flat % adjustment across all charging zones would maintain the locational signal.

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?

No comments.