FutureChargingandAccess@ofgem.gov.uk
25 August 2021

Dear Future Charging Team,

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

EDF is the UK's largest producer of low carbon electricity. We operate low carbon nuclear power stations and are building the first of a new generation of nuclear plants. We also have a large and growing portfolio of renewable generation, including onshore and offshore wind and solar generation, as well as coal and gas stations and energy storage. We have around five million electricity and gas customer accounts, including residential and business users.

EDF aims to help Britain achieve net zero by building a smarter energy future that will support delivery of net zero carbon emissions, including through digital innovations and new customer offerings that encourage the transition to low carbon electric transport and heating.

We believe the proposals are in the right direction and can help solve network constraints / minimise network expansion costs. We support a holistic review of TNUoS, and we would support delaying any decision to introduce TNUoS charges to SDG until there is greater clarity around the role of network charges. This would ensure alignment with the strategic direction of travel for network charges, and alleviate the risk of short-term volatility in charges derived from "change after change". We answer each of your consultation questions in turn below.

If you have any questions, please contact me, or Paul Mott on 07752 987992

Yours sincerely

Mark Cox, Head of Nuclear & Wholesale Policy and Regulation

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<u>Connection boundary</u>

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.

1. Yes. This could speed up the roll-out of low carbon technologies. However, the resulting reduction in connection charges could result in an increased number of applications, which might result in a queue of connection applications.

If the contribution to reinforcement is completely socialised, this could encourage spurious applications, so we prefer to keep a minimum charge to ensure that applications are plausible and realistic.

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 connection boundary/charging approach does incentivise connection in locations which require the least reinforcement. However, connection charges can be so expensive that new DNO connections are inhibited in some places. This could constrain the roll out of low carbon technologies and delay the increased investment that we will need to electrify heat and transport. One option to address this is for more new connections to be “flexible” to allow for quicker connection (i.e. not entirely firm). However, this approach itself raises some potential concerns, including users knowing quite what they are signing up to in flexibility terms, and limits may need to be placed on the DNO use of the flexibility. .. In our view, locational signals are perhaps better given through DUoS and TNUoS charges on an ongoing basis, than through one off connection charges.

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 current arrangements can represent a barrier where the connection cost is very high, both to new low carbon technologies and to efficient developments of the network.

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?

The certainty of price that would arise for new connections does not seem incompatible with greater use of flexibility and other means. However, any future reduction in connection charges could result in an increased number of applications, which might result in a queue. The use of flexibility as a part of connection offers could shorten the queue time by increasing DNO network utilisation.

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 HCC, which does not apply to demand connections today, states that all DNO reinforcement above £200/kW is fully funded by the new DG. It is likely to be far less often in effect – that is, to be comprising an active cap – if the rules are changed as part of this review so that customers no longer contribute to reinforcement at the voltage level above the point of connection. It may turn out to never have effect. However, there is no particular reason to abolish it, as it does prevent very high levels of customer contribution, were that to otherwise be the case.

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?

Customers seeking to connect to the transmission network currently face a shallow connection charge. By contrast, Transmission Attributable work (e.g. upgrading a Grid Supply Point) that has been triggered by a distribution connection is currently charged to the individual connection customer. Small Distributed Generation (SDG) could face the same ongoing network charges as transmission connected generators, but also face an upfront connection charge in relation to transmission costs that a transmission connected generator wouldn't. This if not addressed will lead to a distortion between transmission and distribution connected generation. If the aim of exposing SDG to generation TNUoS is to create a level playing field, then this disparity does need addressing.

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?

As the reform does entail keeping some contribution to reinforcement for new embedded generation in the initial connection charge, we believe that there would still be a financial commitment being made to a project by the developer. This commitment makes it less likely that a project would be cancelled, reducing the risk of project-related inefficient investment from the DNO. Liabilities and securities regimes for new DG would probably be disproportionate given the size of these projects; there is a risk of undoing the benefit of the reform, in that the requirement to provide security (and the complexity of understanding the security regime) might turn out to be as much of a barrier as the existing DG connection charges, and “undo” the effect of the cut in DG connection charges.

We support the minded-to decision not to introduce any new obligations.

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?

We agree that in the case of a subsequent connection, the initial DNO connectee should ideally still be able to receive reimbursement payments from by a later local connectee that they are entitled to under the ECCR, in relation to their own initial (shallower) connection payment, where some assets are now shared by the later local connectee. We agree also that the complexity of these arrangements should be proportionate to the materiality of the problem and what customers can understand.

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?

We support the proposal that new distribution options will be defined in relation to the percentage of time that users are willing to be curtailed. New connectees opting for a flexible connection will be able to choose what percentage of their total access rights are non-firm, and will be protected from the risk of DNOs exceeding the agreed level of curtailment. Presumably there could be some effect on the quoted connection date, arising from these choices as to level of firmness. DNOs will need to measure curtailment rates to ensure that the choice is being respected.

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?

This proposal could allow some parties to connect more quickly, if they can clearly signal that they do not require capacity in periods of peak network loading. Presumably in the second minded-to decision document we may discover if night-only access (for instance) or non-peak access, has implications for DUoS. We suspect that most customers will turn out to want non-time-profiled access, but if there are significant connection cost savings for not taking load for a short duration timeslot, or if a much quicker connection is possible, then some may forgo their right to operate at those times. A reduced DUoS charge (see answer to 4d) would be a more durable approach (because if there is no reduction in DUoS, then there might be nothing to stop customers opting for time-profiled access so as to get a quicker and/or cheaper connection, then asking for 24/7 flat access, having connected quickly and cheaply). There are a few examples, such as electric bus charging depots or electrolysers, which can presumably more easily curtail to night-only etc.

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

As our representative has suggested at the challenge group held as part of this consultation process, we find it hard to envisage that shared access would be taken up. Many complications come to mind in relation to over-run charges, validation and monitoring generally of compliance (and data processing), and disputes between customers in such an arrangement where collectively the arrangement fails and they take too much power.

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)?

We agree that users should receive value when they obtain an access right that avoids additional network costs. The consultation suggests that this value can be provided through three means – allowing the user quicker access to the network than otherwise, and/or allowing them cheaper access, or a lower DUoS charge. We would suggest that the DUoS charge should be lower, which could perhaps be achieved in quite a simple and easy to understand way by having capacity charges that vary at different times of day.

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?

Yes. In truth many new transmission connectees already agree to forgo some aspects of a financially-firm connectee, waiving their bid acceptance rights for some forms of curtailment, in return for an earlier connection date. They do this by signing a “transmission related agreement”. With so many other changes in play at the same time, and no evidence at the challenge group of support from transmission-connected users for such access right choices, this would represent a distraction.

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

It would certainly seem sensible, in the interests of smaller players only having to learn one regime, if the access choices offered in different DNO areas, always entailed the same level of choice / between the same options.

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

In relation to access choices, 1st April 2023 is a good time to aim for. Now that 1st April 2023 has been stated as the time when ultra shallow DNO demand connection charges come in, you need to stick to it, as there is a risk of various entities delaying their rollouts of fast EV chargers until then, that were perhaps otherwise planned earlier, to avoid a DNO reinforcement charge prior to that date.

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, it is a matter of elementary physics, and beyond contention, that changes in SDG's MW output in region A will, *ceteris paribus*, have the exact same effect on flows on region A's export circuits as changes in the MW output of any other type of generation in region A.

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), but with the cap removed. In relation to <1MW SDG, they would henceforth face an incentive to shut down at time of forecast triad, with a small adverse effect on national security of supply at peak demand, but it is understood that phase two of this SCR – the 2nd minded-to decision – will alter or abolish triads.

The suggested threshold is convenient because generators of above this size are required to be included on DNO capacity registers, which came into effect with DCP350 : "Creation of Embedded Capacity Registers". We also believe 1MW is appropriate as this will avoid an incentive for generators to size plant at 4.99MW, as has been the result of other regulatory exemptions. This will ensure that all generators pay at a proportionate level, and avoids creating a perverse incentive on sizing of future projects.

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. It is a simple matter of physics that changes in SDG's MW output connected at a grid supply point in region A will, *ceteris paribus*, have the exact same effect on flows on region A's export circuits as changes in the MW output of any other type of generation, such as that which is directly connected at that spot, in region A.

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?

You have ruled out just removing the cap from the EET, because the triad charging basis for demand TNUoS is different to the formulation and charging of generation TNUoS and its components. This is true, and the different charging basis means there would still be a difference.

Your intended reform of triad could, depending on its form, have an effect in alleviating some of the difference. For as long as triads or something close remains, SDG would receive a perverse signal to reduce export during winter system peak. Therefore your preferred option of levying GTNUoS on SDG, makes more sense.

In Table 5.3 of the CEPA-TNEI Quantitative Analysis Report, a benefit is observed for conventional generators in all distribution zones. We welcomed Ofgem's Decarbonisation Action Plan in February 2020, and the indication of the importance that Ofgem attached to the der net zero transition. This impact may not align with net zero, as intermittent renewable generators in the distribution zones 1 and 2 will face a significant increase in costs, compared to conventional generation, which overall is shown to benefit from this change. This effect is among the considerations to be taken account of.

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 strongly support transitional arrangements such as phasing-in, and would support a delay to the introduction of the start of the reform. A major portion of the UK's future onshore wind generation potential is located in Scotland, and, without tapering-in or grandfathering for operational projects and those on which investment decisions are already made, onshore wind developments at SDG level there will be discouraged, with sectoral investors unsettled. This will also reduce the confidence of investors in existing low carbon generation there. We are already concerned about the unpredictable nature of TNUoS recently, with ESO significantly under-forecasting even 2 years ahead; and therefore, abrupt changes will lead to increased uncertainty.

A grandfathering approach to this aspect of the reforms in respect of low carbon generation type projects could help stabilise the volatility of network charges and maintain confidence. It would mitigate the impact of the reform for users who made their investment decisions under previous regulatory arrangements. Our analysis shows that the introduction of this charge to SDGs would have a significant financial hit on operational wind, and could make the operation of projects post ROC period unfeasible. The introduction of this charge without grandfathering could reduce the operational capacity of onshore wind in the UK, tampering our ability to meet net zero. To avoid a concern about cherry-picking and to limit costs to consumers, the grandfathering, and any phasing-in, could be applied uniformly to all low carbon SDG, including where an abrupt implementation would have comprised a windfall benefit.

If new TNUoS charges are abruptly introduced for even low carbon SDG, the achievement of Net Zero policy objectives might be delayed.

Given our support for a holistic review of TNUoS (see answer to 5g), we would support delaying any decision to introduce TNUoS charges to SDG until we have greater clarity around the role of network charges. This would ensure alignment with the strategic direction of travel for network charges, and alleviate the risk of short-term volatility in charges derived from “change after change”.

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?

Yes.

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?

We would support a wider, holistic review of TNUoS charge calculation and application, and this will be necessary (as a wider part of OTNR, perhaps) to cope with large meshed offshore HVDC wind connections and onshore developments,. The use of peak demand in carrying out both the peak security and year-round studies needs review – is it appropriate, and does it give the expected results? The existing approach to HVDC connections, of fixing a resistance that gives the same load factor as parallel onshore circuits, introduced with CMP213, may become rather stretched or unworkable when HVDC topologies no longer run parallel with the shoreline, or are more complicated and meshed. It is necessary to keep in mind that offshore integrated connections will also entail a lot of new onshore circuitry; the changes to the transmission networks will not tidily end near the beach. The OTNR review looks unlikely to adequately address the onshore network and charging issues. We recommend that an onshore transmission network review is carried out as a complementary exercise to the offshore transmission network review, with an associated wider review of TNUoS. As to OTNR, it is already running nearly 2 years late, and there is nothing publicly being said about what is technically feasible, which will drive the form of meshed networks and size of connections to the shore, and hence charges. Therefore the wider TNUoS review could readily encompass or run closely in parallel with OTNR, given its relatively un-advanced state. Both reviews must be complete ahead of Contract for Difference Auction Round 7 in order to ensure the UK can meet its target of 40 GW of offshore wind by 2030.

A key concern for us is that the current TNUoS methodology results in volatile and unpredictable annual charges. It is this, and not the level/slope, that we refer to. The high level of uncertainty is problematic, and is amplified as a proportion of project costs as the cost of renewables continues to fall rapidly. This volatility is not an inherent characteristic of including a location signal in the charging, but a result of the particular methodology that has been applied. Details of the stabilisation approach will need to be developed in consultation with stakeholders.

You mention re-zoning : our view is that, having decided via CMP324 that there are to continue to be 27 generation zones, there would be merit in keeping that aspect of the arrangements stable.

General question

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

You comment in 5.5 that as links to remote islands develop, you are conscious that embedded generators on an island may export using the cable connecting the island to the mainland, which might be another generator's Local Circuit. Yet you propose not to charge embedded generators on an island, the relevant Local Circuit Charge. You comment that this is not a priority area for reform, so that SDG utilisation of local assets need not be urgently addressed through this SCR. We would simply record that the distortion entailed here is, in the island example, one of unusually high materiality (in the order of £60/kW p.a.).

As to how ESO would recover charges for use of the transmission network from SDG, we prefer the second choice in para 5.27, such that SDG would enter into access agreements with the ESO to establish their capacity, and the ESO would charge them directly. This makes more sense to us in terms of administrative efficiency, once they are paying wider GTNUoS, than using a Supplier or DNO as an intermediary.