ENGIE response to Access SCR Minded to Consultation

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FutureChargingandAccess@ofgem.gov.uk

Background to ENGIE

In the UK in generation, ENGIE owns First Hydro in a 75/25 joint venture with Brookfield Renewable Partners. With a total capacity of 2088MW, it is the UK's largest pumped storage operator.

ENGIE also has a 50% stake in over 80MW of renewable generation and a 23% stake in the Moray East offshore wind project which secured a CfD FiT for 950MW in the 2017 CfD auction.

ENGIE is also active in the Renewable PPA and Corporate PPA space with 37 TWh of contracted renewable generation under PPAs in the UK. These PPAs include both subsidised projects and merchant projects. ENGIE is also a major player in pan European Corporate PPAs.

In supply, ENGIE operates an Industrial and Commercial (I&C) and Small and Medium Enterprise (SME) B2B electricity and gas supply business.

Responses to consultation questions

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 think that moving the connection boundary for demand to be supper shallow is the right approach although for larger connection (three phase) this may need to go hand in hand with a user commitment methodology to ensure that stranded assets are minimised. This would be similar to transmission connected generation where an element of the total connection cost is securitized but with a liability for the full amount should the user not remain connected paying charges for at least [24] month.

For distribution connected generation shallowing the charge also seems appropriate again with security and liability arrangements in place to reduce the potential for stranded assets that continue for [24] months after connection.

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?

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?

It should improve efficiency by removing the step change for users who increases their consumption energy or max demand effectively smoothing the network charging arrangements to allow for the significant increase in heat pump and electric car use. Effectively moving to a linear long run cost model.

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?

It is likely that we will need to see an increased role for aggregators to achieve the benefits of flexible procurement. We would expect to see the development of aggregators alongside these proposals in order for benefits to be optimised. The traditional supplier hub model does not facilitate these services because the link between specific assets and consumers is separated or not optimised without aggregation.

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?

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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?

These should be charged as now with security and liability only designed to prevent stranded assets and not recover the cost of the assets which is achieved by a different mechanism.

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?

With the addition of security prior to connection we would not expect that stranded asset would be a significant issue.

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? Voltage level above the point of connection?

This should not delay the implementation of a new charging philosophy.

4. Access rights (mainly distribution)

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?

Limiting access to timed periods or sharing with other customers all explicitly happen and are organised by the DNO in its fundaments design of the network.

These proposals seek to codify an element of this for individual customers for lower charges. We do not believe that the action of any one party individually results in lower cost as it is this parties action in combination with other parties that that reduces cost.

It is self-evident that solar only need access during high solar days and that domestic demand is shared as users consume at different times. These types of variations are no different   in principle to other aggregation philosophies. We would expect all consumer in area to benefit rather that a specific user or load type. Shared access is at the heart of distribution network design.

At transmission Transmit brought in a sophisticated charging arrangement that adjusts the charges in an area based on how the assets are shared with reduced charges for the whole group when low-carbon- and carbon-based assets share the network. We would support this approach for distribution charges based on the characteristics of the group. A methodology could estimate at GSP level of the volume of solar, wind and consumer demand in a group (based on demand data from high solar/wind days and "dunkelflaute" days) and then produce charges for these classes based on the spare capacity/ long run marginal cost.

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?

See Q1

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

See Q1

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)?

See Q1

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

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

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

Seems ambitious but achievable

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?

We believe that this issue could benefit from a clear technical and commercial analysis to determine the impact on different types of users. The issue was covered in CMP 213 (distribution embedded benefit modification) , the working group report set out the technical position on this issue at the time and concluded that, distribution connected generators have the same effect on power flow as transmission connected generation and as such should be charged in a similar way.

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?

Yes with provision to charge below this if the multiple connection in the same location are being applied for avoid a charge (anti forestalling)

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

Generation behind importing GSP's avoids transformer upgrade.   Generation associated with GSPs that export have exactly the same effect on GSP investment as demand located behind importing GSP's i.e no avoided GSP costs.

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 views on pros and cons. Are there any options we have missed?

Local transmission charges should be applied to SDG in the same way as they are to transmission with the charges be applied to the relevant supplier for assts used by its customers Whilst this is the case at this stage give the number of connections of this type it is unlikely to be high priority.

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?

Grandfathering connection charges is likely to frustrate the pace of change at a time when rapid change is needed to get to net zero. Two customer facing different network chargers for identical assets in the same location fails basic economic test.

That being said we are also mindful that sufficient notice of changing charges may need to be given to groups that are likely to be significantly affected with additional charges this will provide an opportunity for any commercial arrangements to be adjusted. We suggest a 3-year implementation period from Ofgem's minded to position may be appropriate.

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?

If generation charges were moved to a distribution zone method, then charging   SDG TUNOS based on the maximum export (annual) would ensure that transmission and distribution connected generation were treated in the same way. The charge could be based on the previous year max demand with a reconciliation the following year to keep the charging methodology simple. We think that at transmission moving to Distribution zones (plus offshore islands) would resolve many of the issues associated with transmission charges today.

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?

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?

Simon Lord

simon.lord@engie.com