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

25th August 2021

Context

Sembcorp Energy UK (SEUK), a wholly-owned subsidiary of Sembcorp Industries, is a leading provider of sustainable solutions supporting the UK's transition to Net Zero. With an energy generation and battery storage portfolio of nearly 1GW in operation, our expertise helps major energy users and suppliers improve their efficiency, profitability, and sustainability, while supporting the growth of renewables and strengthening the UK's electricity system. Our Wilton International site on Teesside sits within a hub of decarbonisation innovation. At the site, we provide energy-intensive industrial businesses with combined heat and power (CHP) via our private wire network that supplies electricity generated by gas and biomass.

These services are complemented by our fleet of fast-acting, decentralised power stations and battery storage sites situated throughout England and Wales. Monitored and controlled from our central operations facility in Solihull, these flexible assets deliver electricity to the national grid, helping to balance the UK energy system and ensure reliable power for homes and businesses.

Response

We are concerned about the timings of the Reform of Access and Forward-Looking Charges SCR. Whilst we understand and, in principle agree with, Ofgem's desire to implement changes in line with the beginning of RIIO-ED2, the changes proposed under DUoS reform are significant. They are at least as conceptually complex as the changes to the Residual charges brought in under the Targeted Charging review that suffered significant delays due to late publication of the Decision by the Authority that contained only a very high-level of Direction. This meant that key details had to be further discussed and agreed by industry leaving the ESO insufficient time to physically implement the changes required. We are concerned something similar may happen with DUoS charges and DNOs. This is compounded by the fact that DUoS users are less reactive to sudden changes in charges and generally less engaged. In addition, suppliers are likely to be forced to make tariff decisions, or offer advice to larger customers, based on a quite broad Minded-To position from the Authority. Should the final decision be published towards the end of 2021, it is close to impossible for Code parties to write, agree and implement the changes directed and still allow DNOs to give the 15-month notice period required. This will erode trust in the industry, create uncertainty for the user and give the impression that industry parties (suppliers and/or the Authority) are struggling with the current pace of change. Given the ambitious plans required by BEIS and Ofgem for Net Zero, this loss of public perception could be dangerous when changes needed are genuinely urgent. The timescales for this consultation could set a precedent for future reform. It is therefore vital that this SCR continues on a realistic timeline to ensure proper implementation.

We largely agree that changes to access rights for distribution users are a low-regret option and support the proposals, but it seems clear that how they are valued is fundamentally linked to the DUoS charging structure and it is irresponsible to reach a conclusion on them without an Impact Assessment of both. As the elements of the SCR have been split up, it will be extremely difficult for Ofgem to accurately assess the impact of both changes at the same time and exacerbates the risk of unintended consequences.

Given the scale of change already underway to TNUoS as a whole, we believe a decision on charging SDG as generation should be delayed. The indicative tariffs provided by the ESO in the Impact Assessment suggest that all conventional carbon SDG, regardless of location, will receive a negative charge. This does not address the distortion at the heart of this question. We also believe there needs to be wider analysis of whether the current distribution zones would make a suitable charging basis for SDG. It may dampen or distort the nodal locational signal and seems counter-intuitive when there are also plans to introduce more granular DUoS charging for those users. SDG do not have the resources of most transmission-connected generation to engage with the CUSC and so will struggle to understand the wider changes under discussion and therefore suitably judge the impact on their charges.

We would also ask Ofgem to keep in mind the potential for conflicts of interests as DNOs become more heavily incentivised in terms of network optimisation and system operation. Whilst there is work underway to address potential or perceived conflict of interests for the ESO, there appears to be no equivalent concern around DNOs. DNOs are still able to provide ancillary services, though project CLASS, yet will also become responsible for network development. This could create the opportunity for DNOs to increase the need for reinforcement, and thus connection charges for generation, in order to reduce competition in the market they operate. They are also setting up local flexibility markets, which will be directly impacted by the type of users able to connect easily. We are concerned that industry and the Authority will not have the bandwidth to ensure decisions are made fairly. We do agree in principle that encouraging DNOs to take a less reactive approach to network development would benefit most users.

Ofgem’s engagement with industry during this consultation period has been less than might have been expected. Industry parties can sometimes find potentially controversial topics more accessible through direct contact, such as through Energy UK groups, and I believe the feedback Ofgem receives through those sessions can be more useful.

Please see below for our answers to individual questions. If you have any questions, please be in touch,

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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 agree that demand has less discretion when choosing where to locate, although this can be different between types of generation. The nature of demand (industrial vs residential) and relative size of connection cost could suggest the basis for different signals, but this is likely to be impractical. Some types of generation are more flexible with regards to location than others, such as generation which requires exposure to weather patterns or geological features. Local flexibility markets are starting to develop which may be influenced by remaining locational signals through the connection cost. If an area is more expensive to connect to, the local flexibility market will probably reflect that cost, meaning there is a higher local 'system' cost, or that flexibility market is disadvantaged compared to flexibility elsewhere in the country.

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?

No comment

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?

Network development is currently very reactive, with differences in approaches between DNOs. Some DNOs appear to have significantly better visibility of their own networks, such as detailed mapping, forecasts of future growth and usage type. DNOs funding network development themselves may encourage more holistic (and hopefully) more efficient development. The efficiency of network development relies on input from users to form realistic decisions on cost-effectiveness. Transmission network operators have a fairly high level of information from users and the ESO and a good degree of transparency through the Network Options Assessment (NOA) process. It is not clear that DNOs will be able to access similar levels of detailed and reliable information to base forecasts on as engagement from smaller users is generally less. We would look for reassurance that decisions on network development are ultimately overseen by the regulator to ensure DNOs' opinions do not unduly influence their decisions. If DNO network development does not have sufficient independent oversight and transparency, there is a risk of conflict of interest, that DNOs could seek to increase their assets and raise costs for consumers overall.

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?

No comment

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?

We believe that the High Cost Cap should be retained as it protects users. There is no evidence to suggest it is no longer suitable and prevents connection costs becoming an ultimate barrier for projects that would otherwise be viable.

Question 3f: 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?

We believe that transmission costs triggered by a distribution connection should not be targeted at the individual user. The benefit, in terms of extra capacity, is likely to be used by other users connected to that GSP and situations may be created where a connectee at distribution level would end up with a higher up-front cost than if they had chosen to connect to the transmission network.

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?

The energy industry is undergoing a period of significant and rapid change and the push towards Net Zero is increasingly affecting other sectors. The investment space is therefore very uncertain at present, irrespective of charging reforms. We therefore believe it would be prudent for only liabilities to be considered, but not at a level that would discourage innovation and first-of-a-kind projects, such as community-owned renewable generation. We do not believe a liability or security regime needs to be as strict as that for the Transmission system, otherwise it risks becoming a barrier to new connections. While the cost of connection and network development is arguably lower at the distribution level compared to the transmission level, the budget of projects looking to connect is also presumably smaller.

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 comment

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?

We agree in principle but there are serious questions that Ofgem's Minded-To position does not address. It is not clear how compliance with the agreed access rights will be enforced on both consumer and network operator's behaviour. If there is a dispute on the cause of lost access, and therefore whether it is in line with agreed access rights or not, it should be the ombudsman who oversees the disputes process. There is a risk that smaller, less engaged consumers will not have the resources to dispute their access, so network operators should be held to account without direct consumer involvement. This will take extra resources, for the DNO and the ombudsman, the cost of which will need to be recovered from users.

We believe that DNOs should be obligated to offer 'traditional' firm access as well as non-firm options, so that consumers have a choice. Currently, connection offers can be made with Active Network Management only, meaning consumers feel pressured into taking an option that they would rather not, or not connecting at all and looking for a different connection point.

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?

We believe there is considerable interaction between time-profiled access and time-profiled DUoS charges and feel it is inappropriate to attempt to quantify the benefit of one when the other is still open to change. Distribution access rights and DUoS charges must be considered together and the separation of the two within the SCR is inappropriate, invalidating any quantitative conclusions from the Impact Assessment and will prevent a fully comprehensive decision being reached.

As with non-firm access, it should be clear how network operators and consumers are going to held accountable to the agreed access rights, and what, if any, disputes process there should be. We are also concerned that time-profiled access might need to change, as the timing of wider energy generation/usage changes, such as peak times shifting. In that case, it is not clear whether there would be an option to 're-open' the access rights to a time profile that provides the network or the customer benefit or removes the network disbenefit from having the consumer on a time profile that is now no longer suitable.

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

The benefits of shared access rights are dependent on finding compatible users. Users need to be compatible in terms of location, connection type, load profiles, as well as having confidence in other users to sign-up to a long-term arrangement. Finding groups of users with similar requirements seems unlikely unless DNOs actively seek them out. Given the benefits are unclear, this does not seem an efficient use of DNO's resources. Private Wire Networks (PWNs) can be thought of as a type of shared access, but benefits come from other shared resources, e.g. road/rail access, heat network, security.

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)?

Both connection and DUoS charges send a signal to users on where to connect. It is therefore inappropriate to look at the cost-benefits of access rights without considering DUoS charges as well. Given DUoS charges are also part of this SCR, we believe Ofgem will be unable to make a fully comprehensive decision without also taking these charges into account.

Whilst reflecting the network benefits through connection charges may seem similar, the benefits at the time of connection may not last the full lifetime of the connection as the network changes. It also creates the potential for confusion should a customer wish to change the nature of their access rights. They could be reimbursed/charged the difference between what they paid at connection and the connection options now, or charged for a new connection, including any reinforcement if the new access rights requested require it. This could have implications with reuse of sites with existing connections and may encourage users to not reuse existing connection points but request new ones, thus creating inefficient network asset use.

Demand users who can control their usage at peak times already see a cost-reflective benefit: they can avoid peak time charges as DUoS charges are time profiled. Connected customers should therefore also be able to access the same benefit as demand users by utilising time-profiled access agreements, as they have similar impacts on the network. Any changes to DUoS charging to reflect time-profiled access should be considered alongside and within the wider DUoS changes proposed by this SCR.

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. The transmission network is due to undergo significant change over the next few years with increasing interconnection, constraints (and associated costs) and changing usage patterns at the distribution level. New transmission access choices should therefore be viewed in a holistic context and include the results of a wider TNUoS charges review.

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

In order for connectees to make comparable choices, access rights need to be standardised across DNOs. A series of pre-defined options (day/night, morning peak, evening peak, etc.) would allow DNOs to adjust prices to be cost reflective of the conditions of their network. For example, all DNOs could have 7am to 11am as 'morning peak', 11am to 4pm as 'day', 4pm to 7pm as 'evening peak'. DNOs that don't have a cost difference between 'morning peak' and 'day' would set those time periods to the same tariff. Then costs of different DNOs can be compared against the user's expected profile directly.

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

Take up is likely to be slow, as existing sites will wait to see the value that can be accessed before going to the effort of changing their agreement and new investment decisions take time. There is therefore no immediate benefit case. It will take industry time to draw up sensible and coherent business rules that are robust enough to be applied fairly across the country, so April 2023 will be very challenging. Industry discussions will need a strong steer from the Authority on the details or discussions could become circular with industry parties attempting to second-guess Ofgem or provide every possible solution, as happened with CMP317/327. However, given the low-regrets nature of the changes, it may be possible for trials or derogations to be given, or connection offers issued in a regulatory sandbox.

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?

Unless the GSP is exporting, the effect of SGD on the Transmission is indistinguishable from reduced demand. Demand is currently more predictable, but some Future Energy Scenarios

(FES) suggest rising consumer engagement and flexibility on the demand side. To the transmission network, there is no difference between SDG starting to export in response to a market signal and large demand (such as a factory) turning down in response to a market signal. The users' (whether demand or SDG) ability to interact with the market and the ESO would seem to be a better indicator of whether they should be treated the same as large generation.

Most GSPs do not export regularly and therefore the SDG lessens the requirements for the transmission network to import power from elsewhere on the transmission system. This was the reasoning behind the Avoided GSP Infrastructure Cost (AGIC) applied to the Embedded Export Tariff. This should continue for SDG, as it is reflective of the value to consumers saved from having generation close to demand and therefore using less network resources.

The locational signal for transmission-connected generation is much more precise than the demand zones would allow and Ofgem rejected charging generation TNUoS by demand zone in their decision on CMP324/5. If SDG is to be charged generation TNUoS, it would therefore be appropriate to receive a similar locational signal, which would not be possible if nodes are grouped by demand zone. The flows on the transmission network are by GSP, not GSP Group, and so could be considered analogous, when and only when, the GSP is exporting. This is an unusual scenario and so should not be considered as the default state of the network when considering the role of SDG. SDG are more directly analogous to demand users reducing consumption than generators increasing export.

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?

1MW aligns well with other areas of the industry, such as the embedded capacity register. It may create a considerable administrative burden on the ESO but is easier and more consistent. There is the risk of creating a 'cliff edge'. For instance, community projects may be encouraged to build generation just below 1MW in order to avoid industry obligations. A defined threshold, at any level, is likely to create a 'cliff-edge' but the material impacts of a threshold above or below 1MW are likely to be less than a higher threshold.

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 comment

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?

The impact assessment is based heavily on indicative tariffs presented to CEPA by the ESO, but there are significant questions around those tariffs that CEPA are unwilling or unable to answer.

The indicative tariffs provided are unrepresentative as 80% (conventional) and 40% (intermittent) Annual Load Factors (ALF) are unlikely to be suitable for flexibility providers as without the breakdown, users are unable to judge the impact. The modelling in the impact assessment suggests that charging SDG based on the existing TNUoS methodology, applied to the forecast generation mix and network flows, is counterproductive to Ofgem's stated aims.

Looking at the tariffs within CEPA's modelling[1] and comparing to the ESO's latest 5 Year Forecast[2], it is clear the distortion will actually increase for conventional carbon generators in the North of England and Scotland. Under the EET, they would receive no charge or credit whereas Transmission connected generation would receive a charge (up to £30/kW for 80% ALF). In the modelled Impact Assessment, SDG receive a negative charge (i.e. a credit), thus increasing the distortion and encouraging generators in the North of England and Scotland to be distribution connected.

In the indicative tariffs provided, conventional carbon generation is negative across GB, suggesting that conventional carbon will always receive Generation TNUoS as a credit, compared to low carbon or intermittent generators, who may receive significant charges. This is in direct opposition of Net Zero, as it incentivises small gas plants or similar over renewable generation. Given the targets on new renewable generation, it is likely that these increased costs will be recovered by the generators (in order to compete with conventional generators that receive a TNUoS benefit) as higher subsidy prices such as CfDs, or by pushing up market prices. It is unlikely this will be the most cost-effective solution for the consumer to reach Net Zero, but the Impact Assessment does not address this.

The suggested generation TNUoS structure doesn't appear to value Avoided GSP Infrastructure Credit (AGIC). Logically, it is more efficient for power flows to be shorter between generation and demand and not using the Transmission network opens up capacity and/or lessens the need for future re-enforcement. This was a key part of the decision made by the Authority on CMP264/5[3] and the documents provided do not provide any reasoning as to why it should be removed. In

[1] Tables 5.2 and 5.3 in Quantitative analysis of Ofgem Access Options: Connection Boundary and TNUoS SDG

[2] https://www.nationalgrideso.com/charging/transmission-network-use-system-tnuos-charges Forecast From 2022-23 to 2026-27 Report Tables (Published v2), published 30th April 2021

[3] https://www.nationalgrideso.com/industry-information/codes/connection-and-use-system-code-cusc-old/modifications/cmp264-embedded

its decision on CMP264/5 Ofgem's view was that TNUoS "payments made by Suppliers and National Grid to smaller EG are not cost reflective *[before implementation of CMP264]* - as the payments do not reflect the savings in transmission system costs attributable to smaller EG." Arrangements to charge SDG TNUoS should be consistent with that conclusion, which came into full effect in 2020/21[4].

This failure to recognise value, inconsistencies between charging zones and indicative tariffs incentivising carbon generation over low carbon or intermittent, all suggest more detailed analysis is needed before applying Generation TNUoS to SDG, regardless of the massive changes underway with wider TNUoS.

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?

Generation TNUoS charges are currently extremely unstable. Changes directed in the TCR have proved difficult to achieve in practice and delays to the SCR process followed by overly ambitious timelines to industry have damaged users' faith in the process of network charging methodology changes. There are fundamental changes to TNUoS being considered, addressing concepts to the charging methodology, such as the Expansion Constant and how to best apply nodal charges to provide an appropriate locational signal. Most SDG users will not have the understanding or resources in place to usefully contribute and adapt to these conceptual changes yet will be exposed to them.

For SDG that are currently floored at £0 in the Embedded Export Tariff, moving to generation TNUoS will fundamentally change their economic position. A significant proportion of these SDG will be on some form of subsidy, such as Contracts for Difference (CfDs) or 15 year Capacity Market contracts, which could not have predicted this increase in costs when agreeing prices. The Impact Assessment in this SCR alone will not give appropriate warning to those users, and then they will be subjected to further variability as TNUoS concepts and charging evolves.

The results of the Impact Assessment suggest applying generation TNUoS to existing demand zones creates a new, technology-based distortion. All conventional carbon tariffs are negative, even in Scotland where low carbon and intermittent are very high. This is in direct opposition to Ofgem's stated aim of facilitating Net Zero. It also suggests that financial support needed for renewable generation in those areas will be more expensive, and thus not delivered at lowest cost to the consumer.

The Impact Assessment also exacerbates the distortion between transmission and distribution connected conventional carbon generation: conventional carbon plant connected at distribution level will receive a negative charge (instead of £0/kW) compared to a conventional carbon plant

[4] The tariffs for 2020/21 were the first year without the phased residual implementation.

connected at transmission level, which may have a wider tariff of up to £30/kW for 80% ALF. This is a widening of the distortion between similar generation at different voltage levels.

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?

We believe Ofgem has identified the possible options for administering generation TNUoS to SDG. We do not believe that having every SDG enter into an individual bilateral agreement with the ESO would be cost-efficient. It would place a significant administrative burden on the ESO and potentially require careful evaluation of other processes, as having a bilateral agreement with the ESO is often a 'hook' into other obligations, which are not in the scope of this SCR. We also believe a DNO-led model is inappropriate until the role of a Distribution System Operator is more clearly defined.

Our preferred option would be for the ESO to charge suppliers where there is no existing bilateral agreement, as in the current process. This would be the least administratively burdensome for all parties, although suppliers would need sufficient warning to accommodate the increase in workload. It is unlikely that any of the proposed options would be able to go through the change process in a suitably robust manner in time for April 2023 implementation.

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 believe that careful consideration should be given to aggregators, especially if domestic storage, Vehicle to Grid, smart homes, grow in line with more optimistic forecasts. If an aggregator has a portfolio of over 1MW, they should be treated on a level playing field to other flexibility providers.

If domestic generation (e.g. domestic solar panels) become wide spread, as some believe they will need to for Net Zero, consideration should be given to the fact that a town will essentially act as embedded generation, but without the exposure to locational investment signals that a similar sized solar farm would receive.