WESTERN POWER DISTRIBUTION
Serving the Midlands, South West and Wales

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

Consultation response made on behalf of:
Western Power Distribution (South West) plc
Western Power Distribution (South Wales) plc
Western Power Distribution (East Midlands) plc
Western Power Distribution (West Midlands) plc

OFGEM PROPOSALS FOR DISTRIBUTION CONNECTION CHARGING

Q3a: 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.

Yes, we broadly agree with the proposals. Electrification is a reliable and mature route to decarbonisation for a range of end uses and removal of the contribution towards demand reinforcement will best facilitate this.

Demand being consumed as part of another industrial, commercial or domestic end use tends to cluster around existing infrastructure and there is high likelihood any future reinforcement would also benefit other connections and not lead to stranded assets. However, we suggest further consideration should be given to reinforcement required at 132kV (potentially also at EHV), triggered by larger demand connections (such as data server centres or battery Giga factories) where there may be a higher risk of stranded assets.

Generation capacity does not follow the same pattern and can result in large capacity connections triggering wide scale reinforcement. It is right that these connections are not completely prevented, but that they are exposed to some locational signals to maximise the efficiency of the network. Leaving an element of location signalling in the connection charges is the right approach, particularly if there is no signal given through the application of DUoS charges.

The proposed approach works well in incentivising co-location of generation and demand.

Energy Storage (ES) should help support the electricity system. Under the proposals, there is no differentiation for demand consumed for an end use or demand drawn from the system by ES to appear later as export. The current proposals would require DNOs to reinforce the network for ES peak import requirements on top of any other expected demand thereby increasing system costs.

Within the generation licence, Ofgem considers Energy Storage to be a subsect of generation. We believe that to provide greater clarity, for the purposes of the connection boundary, the import from an energy storage device should be considered as negative generation and so follow the charging aspects of a generation connection.

An alternative option may see energy storage being treated as a specific category, in which case we'd propose that by default, energy storage is regarded as being flexible and required to provide commercial control through a method of their choosing, with connections not wishing to provide commercial control requiring an enhanced connection that used a more onerous diversity.

Q3b: 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?

Under the current shallow-ish approach, we have seen reinforcement costs direct customers towards other alternative connection options which may reduce those connection charges. This is most noticeable for generation connections, where we currently have just over 209 of accepted alternative connection offers with a total capacity of just over 1.1GW to date. Whilst flexible connections are also available for demand customers, we have not seen any tangible uptake. Demand customers tend to be wedded to a particular location and usually work with the DNO to find a cost-effective balance of reinforcement or requested capacity reductions to achieve a connection.

We currently offer 4 types of flexible connection options which can benefit customers in situations where the conventional offer triggers significant reinforcement requirement, and would otherwise make the schemes financially unviable. The 4 alternative options include;

- **Active Network Management** - connection offered on the basis that the scheme (typically generator) will join a 'last in first out' queue for forced curtailment at times of peak constraint.
- **Soft Intertrip** - connection offered on the basis that the scheme will be forced offline at times of peak constraint
- **Timed** - connection offered on the basis that the scheme will only operate within a fixed time period.
- **Export Limiting** - connection offered on the basis that the export from the customers' sites into the wider WPD network is capped not to exceed an agreed value, which could be at zero net output.

We believe the proposed changes will reduce the appetite for customers to accept flexible alternatives and encourage existing customers to request an upgrade to a firm connection. For example, generation connections, currently connected and constrained by an ANM scheme, are likely to request an unconstrained connection, which could lead in some cases to significant network reinforcement (unless a flexibility solution was available) where the POC is at the voltage level below the ANM constraint.

As referred to in the consultation document, the proposals may create uncertainty over customer behaviour toward requesting capacity, potentially asking for capacity over and above their needs. This is more likely with demand and could have a wider impact at lower voltages if a number of customers over state their requirements in the same area. This could increase network reinforcement costs initially and lead to networks with excess capacity if customers reduce their maximum capacity requirements after energisation. A pricing signal, potentially tied in to a capacity charge, may be one solution to encourage accurate estimation of demand requirements for a customer connection.

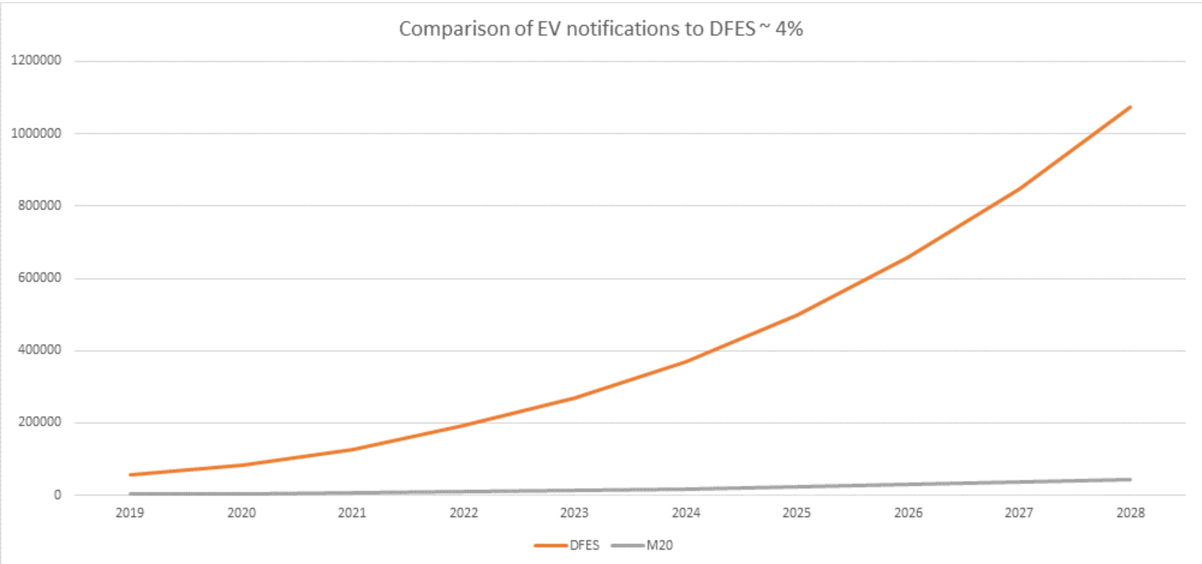
We are also concerned about the potential to experience a bow wave of applications on 1 April 2023 where applicants may have held off in order to benefit from the revised connection boundary. Whilst this bow wave may subside, we could expect to see an ongoing higher base level of applications compared with now as a consequence of lower connection charges making projects more financially viable. DNOs will need to be able to resource this influx and ensure standards of performance are not adversely affected.

Consideration should be given as to any possible transitional arrangements that can be brought to bear to lessen the effect of the bow wave. It is important that DNOs act consistently in this respect so as not to attract criticism from applicants of discriminatory behaviour.

A parallel increase in connection offer acceptances will trigger higher levels of connections activities, including preparatory works such as route survey and consenting. Again, DNOs will need to address resource issues for providing sole use and reinforcement assets although this may provide further opportunities for independent connections providers to step up.

Having access to accurate data on the location of LCTs is very important to ensure our network is developed appropriately. Current EV, PV and HP notifications to the DNO all run significantly under actual deployment rates.

We have seen a significant increase in EV notifications provided to us, across all four of our licence areas within ED1, but this still lags behind the number of electric vehicles we know to be operating within our region. Comparing the DFES data to the ED2 BPDT table M20, which forecasts the current level of reporting out to 2028 shows that only around 4% of EVs result in EV notifications (see below).



We have identified the additional reporting burden and anxiety of triggering connection costs as being barriers, both of these would be reduced under the proposed changes.

Q3c: 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 are generally effective as a cost signal to users in terms of connecting where there is capacity. It can however, also be seen as a barrier and potentially encourages DNO's to reinforce in a piecemeal fashion without incentive to consider a longer term investment approach.

Similarly, load related expenditure set forward by the DNOs is efficiently and timely delivered, but the majority of this relates to modification of distribution voltage assets to accommodate predicted demand growth.

Flexible connections help to optimise existing capacity but only facilitate new connections until curtailment forecasts become prohibitive. At that point no mechanism exists to expand or reinforce the network to create new capacity and facilitate further connections.

Under the proposed changes, the scope of applicable reinforcement is reduced, which will remove or reduce costs borne by connecting customers and place a greater ability on DNOs to undertake strategic investment, rather than connections led investment. The former can more efficiently seek cost effective solutions, rather those that provide the least cost or certain costs to connecting customers.

It is important that Ofgem provide further direction on the application of the voltage rules for connection and consequently the Common Connection Charging Methodology is amended to clarify that the DNO will be still be required to assess the minimum cost scheme when considering the point of connection (POC) to the existing distribution system for a customer. This is key to avoid DER customers asking for a POC one voltage level below to avoid reinforcement costs (e.g. 33kV POC instead of 132kV – if the POC should be 132kV and the customer still wants 33kV, then they should be required to pay towards the reinforcement). An assessment of the whole system cost should be made and the POC determined on that basis.

Q3d: 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?

Certainty of costs is required to ensure there is neither under or over-recovery of investment from connecting customers. This is currently acting as a barrier for the use of flexibility, which has a large variability in costs based on changes in magnitude, direction, volume and length of contract.

The introduction of the new connections boundary may incentivise customers to request 'firmer' connections and this places a greater ability on DNOs to undertake strategic investment, which could use any number of solutions either in isolation or blended together.

The DNO decides how capacity is most cost effectively provided, including through the provision of flexibility procurement in line with SLC13E obligations. With DNOs funding more reinforcement work, opportunities for DNOs to assess flexibility as an alternative to traditional reinforcement will increase although it is also worth noting that flexibility does not create capacity – it allows existing capacity to be used more efficiently.

Traditional ANM systems have delivered a commercially simple (last in first out) approach to mandating curtailment in exchange for quicker and cheaper access to the network. We expect ANM to continue to be required to help accelerate connections in the short term, but it will not form an enduring solution due to the non-optimal way curtailment is allocated. Instead, where flexibility is a more economical solution, this will be procured and dispatched through market mechanisms, such as Flexible Power. ANM will be required to maintain technical operability, but only activated as a last resort. We will develop offerings under the new arrangements with stakeholders and industry.

Investment on voltage levels above the point of connection is also likely to be used for both demand and generation purposes, potentially providing capacity in both directions. Conventional apportionment rules only consider capacity in one direction and subsequent connections may not always contribute to that investment even if they are directly benefiting from it.

Q3e: 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?

If future DUoS charges do not send their own locational signal then the High Cost Cap (HCC) should be retained to ensure large socialised costs are not incurred due to the connection of users who are providing low contribution levels.

There is a case for reviewing the interaction of the HCC with the voltage rule. Again, if there is no DUoS signal the effect of the voltage rule continuing to take precedence will effectively dampen the signal as the HCC will only apply at the voltage of connection. This fact however, should be balanced against the possibility that, should the HCC only apply to costs incurred on the same voltage level as connection, it may still be possible that interventions on voltage levels above can be carried out strategically for future benefit. Flexibility is likely to be used to limit DNO exposure to less certain investment requirements on the higher voltage levels.

Q3f: 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?

Reinforcement related to transmission assets or export constraints requires direct contribution from connected customers ahead of being sanctioned and delivered, resulting in timescales that are undesirable. The extent to which those costs are apportioned to connecting customers also presents problems, with many customers preferring to seek other options, such as flexible connections, which reduce or avoid the costs.

We acknowledge the removal of any further direction under the SCR on the transmission boundary approaches – leaving this alone is sensible. However, this will not address aligning the treatment of transmission reinforcement at DNO/connection sites and TO/infrastructure sites. The latter has all costs socialised either through TNUoS or BSUoS. The former is down to the DNO interpretation under the CCCM.

Traditionally, where the reinforcement trigger is undefined (aggregate load growth), DNOs have socialised these costs under DUoS (providing they are within the cost allocations identified within the price control planning period). However, where there is an identifiable customer triggering these works, then these have been passed through to that customer without apportionment, as it is unknown/unlikely whether all of these costs can be recovered from subsequent customers. This has led to potential barriers in additional export capacity being created, and hence the huge uptake in ANM.

We believe there is a case to review the CCCM to allow a similar connection boundary treatment to be applied for this transmission reinforcement – i.e. socialised under demand or apportioned if triggered by generation schemes connecting to same voltage level. In practice this would leave the transmission elements to be non-chargeable and only the distribution voltage elements to be apportioned to generation connections at 132kV (33kV in Scotland).

This would allow similar treatment for connection asset and infrastructure sites, as well as opening the DNOs to fund flexibility market opportunities for generation turn down, demand turn up across GSP areas.

We think this needs to be considered alongside wider charging reforms and achieving any change by 1 April 2023 would be very challenging.

Q3g: 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?

Whilst there may be some additional risk that investment will be carried out to accommodate demand, generation or storage which later cancels, this risk will ultimately be borne by DNOs, who are well placed to manage this through queue management, ANM for connections or developing flexibility markets. We expect Ofgem to ensure investment is not carried out inefficiently using existing reporting mechanisms.

Liabilities and securities may be appropriate for where the level of upfront payments for connection are small compared to the wider costs of reinforcement works and where there is a greater risk of a single large connection triggering investment which may not be recovered through subsequent connections, however this risk of this on the distribution network is much lower and the administration burden would be much higher due to the number of connections.

Furthermore, some distribution customers are already subjected to transmission cancellation charges and provision of security for this charge. The introduction of cancellation charges for distribution connections would impose high financial burden on these customers and potentially make these connections less viable so whilst some form of signal might be desirable to protect DUoS customers from paying toward stranded assets this should be balanced against the potential to create further barriers to connection customers.

Q3h: 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?

The connection reforms could have an effect on the application of the ECCR's, specifically where a 'second comer' who connects under the new charging regime may not be expecting to contribute to previous DNO (DUoS) funded reinforcement. Currently there is an obligation under the ECCR's for the DNO to demand a reimbursement payment from the person obtaining the second connection.

Initial assessment indicates that the most pragmatic solution is to implement a change to the ECCR's that would remove the obligation on the DNO to demand payment under this scenario as not making a legal change could increase uncertainty and challenge from users.

We understand however, that delivery of a legislative change within the timescales set out for implementation make this unlikely. We therefore support the proposal to explore an alternative viable solution that could be utilised either as an interim measure while legislation is changed or as a more enduring solution. This support is given on the basis that any non-legislative proposal is suitably robust and does not result in the DNO incurring significant costs and additional administrative burden.

OFGEM PROPOSALS FOR DEFINITION AND CHOICE OF ACCESS RIGHTS

Q4a: 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 broadly agree that new non-firm access options should support efficient network development in accordance with user requirements. Access defined by user experience of curtailment will provide more certainty to connected users about how much they will be curtailed. However, facilitating access rights via consumer outcomes could impose an additional burden on DNO's.

Terminology around the firmness of connection needs to be more explicit. Demand connections enjoy a level of security afforded by Engineering Recommendation P2. There is no equivalent for export connections, which tend to be regarded as "firm" if they are not curtailed under network intact connections. They would still potentially have access curtailed or removed for situations where the network is not intact. If a generator wanted an n-1 secure connection and their alternative feed triggered additional upstream reinforcement, it needs to be established whether it is reasonable for this cost to also be socialised. The methodology will need to be established once the final access choices are known.

Non-firm connections as outlined in the SCR refer to connections which are likely to experience curtailment under network intact conditions.

Further clarity is also needed relating to customer choice/agreement, i.e. can the customer choose or dictate a required level of firmness or is any contract a result of negotiation and agreement?

Q4b: 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 agree that new time-profiled access options should support efficient network development in accordance with user requirements. The development of time-profiled access rights will encourage users to move export or import away from system peaks.

We would be in favour of the DNO identifying the peak windows for import and export across all GSPs on an annual basis and then the connecting customers deciding the level of firmness acceptable based on a percentage of time curtailed, or a specific number of half-hours. Both could be identified if the curtailment could apply just for peak or also for non-peak time periods too. DNOs are unlikely to require (or explicitly value) curtailment at non-peak time periods, but it may provide additional operational flexibility.

Specific modelling of the cost reductions for a particular flexible connection is likely to be highly variable depending on the load profiles, forecasts and subsequent connections. A more pragmatic approach may be for DNOs to discount the reinforcement contribution by the market rate of flexibility afforded by the proposed level of firmness. This would then be similar in approach to existing ANM connection whereby a 100% flexible connection would see no reinforcement contribution.

We anticipate demand flexibility to have a lower take up under the proposed approach due to the differences in connection boundary.

Q4c: 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 not proven and there remain concerns surrounding eligibility criteria, commercial relationships and administrative burden. Therefore the ENA Open Networks should undertake further work in this area to better identify the practicality of this option and the likelihood of user take up.

An open market based approach administrated by DNOs as part of their neutral market facilitation role would result in better whole system outcomes.

Q4d: 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 upfront connection charges are the best place to reflect network access arrangements, particularly where the network access arrangements are defined at that point in time.

However, as locational cost signals will be reduced for generation and largely removed for demand we believe that DUoS charging reform is vital in order to apply some level of signal according to access rights.

Q4e: Do you agree with our proposal to not prioritise the introduction of new transmission access choices as part of this Significant Code Review?

Yes, it is most appropriate to prioritise changes for distribution network access choices under the SCR.

The relative benefits of reform at transmission level are not yet proven and has not been identified as a high priority by transmission stakeholders as they are of significantly lower use.

Q4f: Do you have views on how access rights should be standardised across DNOs?

This work is best undertaken as part of Open Networks. We expect this approach would be able to deliver the required standardisation within the proposed timescales.

Q4g: Do you have any views on our proposed timescale of 1 April 2023 implementation?

We are concerned that the timescale for implementation is very tight considering the level of work that needs to be undertaken. Ofgem needs to provide more detail and guidance as soon as possible to allow the industry to make suitable plans and implement changes.

Any required changes to licence, regulations and charging methodology will require time to develop, consult on and implement.

DNO's will need to make system changes to facilitate the new access arrangements. This will include time consuming substantial re-design of systems that are able to record additional data to measure curtailment rates.

These activities come at significant cost and are not accounted for in DNO settlements made under RIIO-ED1. They will therefore need to be factored in via an appropriate mechanism, e.g. included as an ex-post in RIIO-ED2 settlement.

None of this can be initiated without a clear steer on how the minded-to position will unfold. While we accept that work to firm up ideas will continue at industry level, Ofgem is unlikely to issue a final decision until late this year which effectively leaves industry only 15 months to develop, test and implement changes. It is highly unlikely that such development could be delivered and tested within the proposed implementation date.

OFGEM PROPOSALS FOR TNUoS CHARGES FOR SDG

Q5a: 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 have no comment on this.

Q5b: Do you agree with our threshold for applying TNUoS generation charges of 1MW? If not, what would be a better threshold and why?

We have no comment on this.

Q5c: Do you have any evidence that distribution connected generation at a grid supply point has a different impact than directly connected generation?

We have no comment on this.

Q5d: 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?

We have no comment on this.

Q5e: 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?

We have no comment on this.

Q5f: 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 that Ofgem has identified all the viable options for applying administrative arrangements for charging SDG.

We are not supportive of a mechanism for the ESO to recover charges by charging the DNO TNUoS due to the likely costs for DNO implementation compared to a supplier-led approach. Under this arrangement the DNO would agree transmission access with the ESO on behalf of the SDG – DNO would need to bill the supplier for their combined DUoS and TNUoS. This could potentially put DNOs at risk of additional bad debt through supplier default. There would be a significant cost to the DNO to develop billing systems to cope. It is better that all SDG enters into access agreements with the ESO to establish their capacity and then the ESO charges the supplier for TNUoS charges.

DNOs could support this process through providing ongoing data on connection agreements, the majority of which is already published through our embedded capacity register and is submitted to National Grid ESO on a monthly basis via our Appendix G Statement of Works process.

Q5g: 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?

To align with the statement of works process, the threshold should be based on connection point export being 1MW and above, not installed capacity.

GENERAL QUESTION

Q7: Do you have any other information relevant to the subject matter of this consultation that we should consider in developing our proposals?

We have a general concern that the timescales for implementing the changes by 1 April 2023 are very challenging, particularly because of the potential impact on codes/legislation/licence and the need to update internal systems to cope.

We are also concerned as to how we will be able to consider the market response to any proposed changes and consider the implications of this in to our final RIIO-ED2 Business Plan due for submission to Ofgem on 1 December 2021. In the consultation paper you highlight there are important interactions between the proposals set out and the RIIO-ED2 price controls and that any reforms could change the amount of funding required as part of the RIIO-ED2 price control or could require the introduction of new obligations or incentives.

We welcome that Ofgem recognises this fact and that you are committed to working with DNOs and wider stakeholders to manage these issues but still conclude at this stage of the price control process that it is very difficult to make changes to the Business Plan when there is still little detail to be had. We believe further clarity is needed to help us reassess the impact and having sight of the decision document 'late' in 2021 will not give us the time to base our assumptions on anything other than Ofgem's minded-to position. As a consequence, we would welcome clear guidance in the next iteration of the RIIO-ED2 Business Plan guidance from Ofgem, detailing SCR assumptions, at the earliest available opportunity. It is important for all DNOs to have clear direction from Ofgem on what to include in our business plans to ensure baseline plans are comparable and any required uncertainty mechanisms can be considered to ensure consistency.

It is difficult to assess what impact your decision on the connection boundary will have on the volume or types of distribution connections during RIIO-ED2) although it is clear there will be an increase in activity from both new and existing customer looking to increase and/or 'firm up' capacity, which will alter the costs to be recovered through the price control. As a consequence uncertainty mechanisms will need to be developed to mitigate the risk to DNOs of under/over recovery of allowed revenue.

All these changes impose new costs and risks on DNOs whether that be through costs for network monitoring systems or additional resources to cope with an increase in activity and to continue to meet regulatory timescales for quoting and connecting.