Company	Confidential / Anonymous	1. Do you agree with the Working Group to bill the Primary supplier based on gross metered data from the boundary settlement meter for shared metering arrangements in preference to each supplier based on the fully settled solutions suggested in the first consultation. Please provide your rationale in the response.	Working Group Comments
Emergent Energy Systems Ltd.	Non-confidential	No. We do not agree that the Primary supplier should be billed on gross metered data from the boundary settlement meter for shared metering arrangements. Emergent was recently awarded a BSC Sandbox trial by Ofgem, following detailed work with Elexon that focused on the deficiencies of the current arrangements for enabling customers on private networks to by supplied by a third party supplier. We view this consultation on changes to DCUSA as flawed because it has not taken into account these deficiencies, which have been recognised by Ofgem and Elexon in their award to us of the Sandbox trial. The basic issue is that the difference metering provisions that are in place were evidently designed to support 3rd party supply arrangements for I&C customers and not residential customers. This should be of significant concern to the industry due to the rapidly growing interest in and incidence of residential electricity private wire based microgrids in the UK. Emergent would be happy to provide details on eight organisations who are currently operating such systems serving thousands of residential customers. The issue we raised in our Sandbox application was that, while the current difference metering arrangements may theoretically work for residential customers, in practise they do not, because the onus of responsibility for establishing the difference metering arrangement lies with the residential customer, who has little power or leverage to implement the arrangements. i.e. it is up to the customer to find a third party supplier who will agree to a bespoke tariff arrangement that would involve the supplier settling their meter half hourly (not standard industry practise today for residential customers), as well as assigning the same metering arrangements to that meter (HHDC, HHDA, MOP) as are in place for the boundary meter (requiring a bespoke bilateral agreement between the boundary point supplier/agents and the third party supplier/agents) such that those metering arrangements could then perform the difference metering arrangement. In practise no supplier will do this for a residential customer, since a) the bespoke work required is not compatible with their systems which are built for high volume customer management; 2) to the degree that a supplier would offer such a tariff, it would	

		necessarily be on the basis of an extremely high tariff, to cover the high implementation costs they face. One must also consider how in a typical residential private wire arrangement, there could be many third party supply arrangements in place, so the bilateral contracts needed to fulfil the difference metering arrangements become extremely complex, again prohibiting their implementation in practise. E.g. consider the contract arrangements required for a housing estate of 100 properties, where 50 properties choose to be supplied by a third party, and the supplier to those 50 properties are provided by 10 different licensed suppliers. Due to these problems, Emergent developed an alternative to difference metering for private networks that would remove any dependency between the boundary point MPAN/agents and MPANs/agents of customers who are supplied by third party suppliers. The details of this can be seen in the relevant Sandbox application documentation, including Elexon's submission to the BSC committee, but essentially it involves an accurate boundary point reading being attained by aggregating the value of all metering points on the private network excluding the third party supplied customers. The consequence of the solution is that customers who want to be supplied by a third party supplier can do so without any detriment Vs a customer who is connected directly to a licensed distribution system. Meanwhile, accurate readings can be entered into settlement for the boundary meter. Unfortunately the DCUSA proposal that forms the basis of this consultation appears to be making a similar mistake to the way in which the original difference metering arrangements were established, by prioritising the needs of industry participants (i.e. for a simple and easy arrangements) above what is best for customers. The proposal reinforces the need for bilateral agreements and alignment of metering arrangements between the third party suppliers and boundary point supplier on any single network. By forcing the private network operator to enter such agreements if they are to achieve fair and accurate charging of DNO costs, there is little incentive on them to implementation the aggregation methodology that is being trialled by our Sandbox scheme to take place, which would improve outcomes for customers alongside accuracy for settlement.	

		The proposal will therefore simply reinforce the ineffectual status quo where customers on private networks will need to find a supplier who provide them with a bespoke tariff if they are to receive a third party supply. Instead of this approach, DCUSA should instead be focusing first on what is best for customers, and then working out how this can be best be delivered by the industry. The goal should be to make the process of switching as simple as and easy as possible for customers, such that the experience is as close to switching for customers connected to licensed distribution systems as can possibly be achieved. Shifting the onus of responsibility for establishing the differencing arrangements away from customers in this way will simply mean industry participants having to work out between themselves how best to ensure DUOS charges are being correctly allocated, without recourse to bilateral contracts. While we have not yet had opportunity to develop a robust solution for this, it should be simple enough to be achieve: so long as the relevant DNO for any particular scheme is aware that a private network arrangement exists (as will be the case with our Sandbox aggregation methodology), they can simply charge MPANs associated with the third party suppliers at the usual rates, and then deduct these charges from the charges allocated to the boundary point MPAN. Alternatively, we may be able to use the aggregation methodology we have established for the Sandbox trial, in which case perhaps a Sandbox trial for DCUSA that emulates the BSC Sandbox would be appropriate. We would welcome the opportunity to discuss with you alternative solutions to those proposed that would better serve the needs of residential customers. We do not believe sufficient engagement has occurred with the existing and growing number of stakeholders in the residential private network sector. Unfortunately, as drafted, these proposals will work contrary to the efforts that Ofgem and Elexon have made to improve outcomes for residential customers on private networks, through the Sandbox award they have made to Emergent. We believe it is vitally important that greater consideration be given to how these proposals will impact residential customers on private networks before they are implemented.	
Electricity North West	Non-confidential	We strongly agree that billing the Primary supplier is the best solution as it would provide consistency between charges to private networks with competition in supply and private	

		networks without. This would also be compatible with current industry arrangements and billing systems. We believe all solutions should focus around identifying a primary supplier and ensure DUoS charges are billed to them based on the boundary load as per arrangements with a single meter on the boundary. We support competition in supply but these arrangements should not lead to different network service provision or charges by the regulated DNO.	
ESP Electricity Limited	Non-confidential	Yes, we agree with this approach. Billing the primary supplier would be more simplistic and therefore preferred over billing multiple suppliers.	
Northern Powergrid	Non-confidential	Yes - since the boundary settlement metering data is available using it to bill the primary supplier on gross metered data, rather than to bill each of the embedded suppliers, is the most practical, efficient and effective way forward. Adopting such an approach is also consistent with the way difference metering is treated.. The primary supplier would then be responsible for recovering the charges from the embedded suppliers in line with agreements between the suppliers. This would mean that the DNO/IDNO Party would only need to know the boundary capacity and would only charge a single fixed charge at the boundary and would therefore be recovering the correct amount of revenue from the system without the need for the creation of a significant number of new tariffs or the introduction of a mechanism to process rebates. It would also allow the current billing arrangements to be maintained for these MPANs.	
Power Data Associates Ltd	Non-confidential	Yes. It makes application of the DUoS charges simpler and straightforward. There are a fairly small number of shared metering customers	
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	Yes – it's a tidier solution and should be reasonably straightforward in terms of administrative burden. Not all PNO Boundary points are metered where full settlements arrangements are in place.	
ScottishPower Energy Retail Ltd	Non-confidential	Understand the analysis carried out and appreciate it is the most efficient and simplest solution currently available.	

SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	We agree with the working group that DUOS can be charged to the primary supplier based on grossed meter data from the boundary meter for the shared metering arrangements. Our support is qualified in that the DC is responsible for providing the gross data. However we have experienced issues with receiving gross metering data from a DC even when difference metering is involved. The DC is saying under BSCP guidelines they do not need to send the gross data to the distributor. ELEXON needs to bring clarity with regards to this.	
SSE Generation	Non-confidential	Yes, we do. It appears to us that the shared metering arrangements have more in common with difference metering arrangements than with fully settled arrangements. In particular, they both have a supplier at the boundary who could act as the single DUoS invoicing party for a single site (which is the proposed solution for these metering categories), whereas this is not the case under fully settled arrangements (for which a different approach is proposed).	
The Electricity Network Company Limited	Non-confidential	We believe this is likely to be the simplest, and only viable, solution and would result in charges being levied on boundary MPANs where competition in supply exists which are broadly equivalent to those where no competition in supply exists. Our concerns with the alternative option are outlined below To illustrate the issues with other options further: (a) Private network operators are not party to the DCUSA; they only connect to the distribution system as a consumer with use of system charges being levied to the appointed supplier for the relevant exit or entry point from the distribution system. The DCUSA does not prescribe the contractual relationship between the supplier and the private network operator, or between the private network operator (operating as a distributor through licence exemption). The only contractual relationship between the private network operator and the licensed distributor is through the connection agreement (or the National Terms of Connection where such bespoke agreement does not exist). (b) SLC 12.1 of the distribution mandates that a licensee: *"…must, on receiving a request from any person ("the requester") asking it to do so, offer to enter into an agreement for Use of System under which it will:* *(a) accept into the licensee's Distribution System, **at any Entry Point** and in any quantity that was specified by the requester in the request, electricity that is provided by or on behalf of the requester; and*	

		(b) distribute that quantity of electricity (subject to any distribution losses) ***to such Exit Point on the licensee's Distribution System*** *and to any person as the requester may specify." (emphasis added).* SLC 12 places no obligation (nor does the Electricity Act 1989) on the licensee to provide services for use of system beyond their distribution system boundary. It is also unclear from a settlement perspective to what extent metering points on private network can be constituted as forming part of the Total System since the private network operator is not part to the BSC or any other industry codes. (c) We disagree with the assertion in paragraph 3.2 of the consultation that *"…the Distributor is obliged to provide Meter Point Administration Services to customers on the private network"*. SLC 17.1 only places an obligation on licensed distributors to offer MPAS in respect of premises connected to its distribution system. SLC 17 places no obligation on distributors to offer MPAS on third party networks. Although SLC35 sets out an obligation to provide MPAS and Data transfer Services, the duty only applies to DNOs operating within their distribution services area. It does not apply to IDNOs or DNO networks which are outside their distribution services area. Either way, the provision of such services is subject to agreement – such agreement would be between the private network operator and the relevant DNO. Therefore whilst a DNO may obliged to offer MPAS services to a private network connected to an IDNO network, the IDNO is not. We are not clear how the difference metering works in these circumstances. We presume that any such agreement to provide Data Services could be incorporated into a connection agreement and would among other things, include charges for the provision of the relevant services We think it is outside the vires of DCUSA or the BSC to place duties on a distributor that extend beyond the scope of the licence. SLC14 places a duty on the licensee offer to "…*enter into an agreement that authorises the applicant to connect Metering Equipment to the licensee's Distribution System*", this does not extend to private networks. Therefore suppliers and meter operators would need to enter into their own separate arrangements for the connection of metering.	
UK Power Networks	Non-confidential	We have concerns regarding this approach, as we have historically received feedback from DCs that they are not able to provide such data, it would be worth obtaining appropriate and up to date feedback from both HH as well as NHH DCs to confirm that they are comfortable with this approach. This solution would require creating MPANs,	

		that the appropriate DC would need to be aware of, including where the DC appointment changes, which would require further revision of the Legal Text. We believe that the DNO should be allowed to estimate HH data based upon the agreed MICs. All Settlement MPANs for both the boundary and inset customers would also need an LLFC which is assigned to a zero tariff to ensure no double charging existed.	
Western Power Distribution	Non-confidential	The existing arrangements are preferable as these were wanted by the customer in the first place. However, the new option seems straight forward for DNO as long as boundary metering data exists and if the new option is straight forward for the supplier.	

Company	Confidential / Anonymous	2. Which metering data option to you prefer? Please provide your rationale, including any cost impacts.	Working Group Comments
Emergent Energy Systems Ltd.	Non-confidential	n/a	Noted
Electricity North West	Non-confidential	Both options seem to be valid, but the system costs for Option 2 may prove to be prohibitive, so our preference of the options presented would be Option 1.	Preference for Option 1
ESP Electricity Limited	Non-confidential	We support metering data option 2. This option does not require the additional activity of issuing non-settlement MPANs and does not present the compliance concerns noted by the Workgroup. We recognise that there will be system change costs but have not carried out a cost assessment at this time. We believe these costs will not be material.	Preference for Option 2
Northern Powergrid	Non-confidential	**Option 1 – gross data received from the boundary Supplier's or Primary Supplier's Data Collector.** Under BSCP514, the same HHMOA and HHDC must be appointed to both the boundary and embedded meters. This means that the total volumes, as measured at the boundary, and the differenced volumes are already being processed by one single data collector. As such the most practical and efficient way forward would be for that data collector to populate a D0036 flow with the total volumes, which does not appear to be a significant	Preference for option 1

		increase in work. This would then mean that the DUoS billing systems could continue to work as they currently do. **Option 2 – Distributor calculates the aggregated boundary data.** In contrast, in order for option 2 to be used there would need to be a significant change to the DUoS billing systems of all DNO/IDNO Party(s) in order for the data from multiple suppliers to be aggregated together for billing in total. This is currently not possible and would require a new process to be implemented in the billing system to identify which MPANs should be aggregated together, which will introduce additional cost to the process.	
Power Data Associates Ltd	Non-confidential	neutral	Noted
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	Option 1. Durabill can deal with this currently; so minimal cost implications, if any.	Preference for option 1
ScottishPower Energy Retail Ltd	Non-confidential	We have no clear preference. As mentioned above, it has to be the most efficient and simplest to understand. However, we do question how easily identifiable these would be if the MTC or Metering Point Address line 1 are not used? Will it be LLFC?	Noted no preference, Noted that concern is with respect to Option 2 as there isn't a flag at present
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	Option 1 is our preferred option as it follows a similar approach already in place for difference metering whereby the DC of the primary MPAN would send gross boundary meter data in D0036 or D0275 format. St Clements believes that it is unlikely that any changes to DURABILL will be required to support the approach described in paragraphs 4.34 – 4.37, as long as the following assumptions are correct: i) DNOs can chose to receive the data in D0036 rather than D0275 format	Preference for option 1 Working Group noted the useful information provided and will extract relevant parts for the change report

		ii) The D0036 file containing the DC calculated boundary meter reads will either be sent over the DTN or emailed directly to DNOs for loading via DURABILL's existing manual flow submission functionality. The consultation document highlights that the working group believe the DNO's systems will need to be changed to ensure that only boundary suppliers on shared metering PNO sites are billed. DURABILL already has functionality which can be used to ensure that only boundary units are billed. This functionality is already in use by DNOs for difference metering and includes: i) The ability to automatically reject meter data for certain MPANs ii) The option to either not assign an MPAN to a tariff – whereby an invoice will not be produced for the site or assign it to a zero-rated tariff iii) The option to not create / remove the secondary MPANs from the system. We assume that the number of sites that will be billed via this method is fairly small, therefore the additional data management required to support billing shared metering systems using this functionality will be minimal. If this assumption is incorrect, this may require additional resource in order to manage the necessary updates to the system. Please note that the consultation document indicates that the DC will be responsible for providing the boundary meter reads under this option. Under the proposals for Market Wide Half Hourly Settlement (MWHHS) this role will no longer exist. Option 2 proposes that the DNOs aggregate the boundary meter data themselves and then bill based upon these aggregated values. The consultation document indicates that billing in this way would be 'based on the same approach adopted for connections to the distribution network where a site is connected by multiple feeders'. St Clements do not believe that it's possible to use DURABILL's existing multi-MPAN site billing functionality to do this, principally because: i) We assume that the PNO networks may contain both import and export connections whereas a site for billing purposes needs to be either import or export – none of the existing processes for aggregate meter data on multi-MPAN sites handles both active import and active export	

		ii) It is likely that sites within the system will have different suppliers, LLFCs, measurement classes – significant changes would be required to data management, control reports and billing processes to enable billing of these 'sites' iii) DURABILL does not have any functionality in place to aggregate data allowing for losses and/or the allocation of 'unaccounted for' active energy as per the rules within BSCP550. While this may not be required on smaller sites it may not be appropriate to introduce such differences between DNO calculated and actual boundary meter data. New functionality could be introduced to calculate the boundary meter data including the following changes: i) New process to calculate boundary meter data ii) Screen changes for the MPAN registration and Maintain a Site screens to enable PNO connected sites to be recorded in the system. These screens would need to have different restrictions on how sites are set up to DNO connected sites iii) Changes to the HH billing module to enable appropriate billing of PNO sites iv) Amendments to invoice prints v) Changes to the production of the D2021 flow vi) Report changes e.g. invoicing, meter data and/or control reports such as the MPAN reconciliation report Please note that while the consultation document makes no references to changes to invoice prints and the D2021, as the method of calculation is different from DNO connected sites St Clements have assumed that some small changes may be required. The costs of implementing the necessary changes within DURABILL are anticipated to be in the region of £160k to £300k split between all DURABILL customers. If the number of PNO connected sites are significant, DNOs may also wish to make amendments to REG02 processing and HH auto-tariff assignment to improve the efficiency of data management processes for these sites. Any such changes are likely to be in the region of £90k split between all DURABILL customers. This may not be cost effective if the number of affected sites is believed to be small. DNOs may also need to make changes to their internal reporting solutions such as DataMarts or Business Objects universes. This is because it is anticipated that both the calculated boundary meter data and from the settlements meters will be in the DataMart and customers may need to exclude some of these reads to ensure that there is no	

		double counting. Any such changes are specifically excluded from the costs quoted above. It is likely that significant testing of the new functionality along with regression testing of HH billing will be required before DNOs could put these changes live. DNOs should consider the costs of this along with the costs associated with installing the new release when submitting cost estimates for this development.	
SSE Generation	Non-confidential	We have no preference regarding the two metering data options for difference metering and shared metering.	No preference
The Electricity Network Company Limited	Non-confidential	We believe the first option, for the boundary or primary supplier to be provided with a non-settlement MPAN against which they will submit data to the distributor in respect of the gross consumption at the boundary is the most viable. This is likely to be the least cost solution as we would need to make changes to our billing system to facilitate the solution under option 2. We are not, at this stage, able to quantify those costs but if the working group requires this assessment to determine the most cost reflective solution then we would be willing to provide it at a later stage. As we have indicated in our response to question 1, there is no licence obligation on IDNOs to offer MPAS in respect of metering points not connected to their distribution system. Therefore, it would for IDNOs to choose if they wanted to offer such service. Offering such service would be dependent on IDNOs being able to recover their costs. Notwithstanding the above, one approach would be to use a default LLFC for such metering points and to set the tariff to zero, or to such other charge to recover the additional costs for providing services to the licence exempt network	Preference for option 1 Notes the points raised in regards to IDNOs and MPAS, specifically the lack of ability to recover their costs.
UK Power Networks	Non-confidential	Of the two options proposed we support option 1 for how metering data is treated, this utilises existing arrangements and minimises total cost to industry, although any changes brought about by this change would need to be watched when any changes necessary for MHHS are taken forward. As stated in the consultation document option 2 would result to system changes and costs to Distributors which would not be required with option 1. In the small number of Private Networks we have connected to our networks we utilise an approach where we apply the fixed and capacity charges to the boundary and the units split between the boundary and inset customers based upon where they have been consumed, although this isn't perfect and is not without issues it does allow an relatively effective approach which results in limited manual intervention.	Preference for option 1 Notes the approach set out by this respondent and will consider further if other options aren't supported….

Western Power Distribution	Non-confidential	No preference. Option 2 will require addition cost shared between the DNOs but Option 1 will be done by a role that may not exist in market wide HH settlement.	No preference.

Majority (6) had preference for Option 1:
Minority (1) had preference for Option 2:
Others: no preference or no response
Themes:
Option 2 will require system changes which addition cost shared between the DNOs
Option 1 will be done by a role that may not exist in market wide HH settlement.
Other concern:
Option 2 "As we have indicated in our response to question 1, there is no licence obligation on IDNOs to offer MPAS in respect of metering points not connected to their distribution system. Therefore, it would for IDNOs to choose if they wanted to offer such service. Offering such service would be dependent on IDNOs being able to recover their costs"

Company	**Confidential / Anonymous**	**3. Do you have any comments on the EDCM solution?**	
Emergent Energy Systems Ltd.	Non-confidential	n/a	-
Electricity North West	Non-confidential	Any solution that alters the overall charge to a PNO in comparison with an equivalent customer with a single meter is not acceptable. Furthermore, Solution A appears to create a difference in the structure of charges (and potentially the actual PNO customer bill) for fully settled metering arrangements between the CDCM and EDCM, which could lead to distortions in competition or changes in customer behaviour.	Noted
ESP Electricity Limited	Non-confidential	No comments.	Noted
Northern Powergrid	Non-confidential	The EDCM solution removes the issue of overbilling the fixed and capacity charges for these customers, in a simple way. PNO sites are easily identifiable in the EDCM and the information required for this solution (capacities of embedded customers) should be accessible either from the connection agreement or directly from the customers.	

Power Data Associates Ltd	Non-confidential	No comments	Noted
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	Does this create an obligation on the DNO to procure the necessary input data (ie MICs) for modelling; or on the PNO or their customer to provide it to the DNO? Clarity required as to who's responsible for the collection of these data: it be would be sensible to follow the network relationships and for the PNO to lead this.	Noted the request for clarity as to who will be responsible, however as PNOs are not Party to the DCUSA and therefore
ScottishPower Energy Retail Ltd	Non-confidential	No	
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	The EDCM solution for fully settlement sites described in the consultation document is a two-step process: i) Use the Settlement metering data of each embedded customer within the relevant PNO network to determine the power flow data at the boundary for both import and export charges ii) Allocation of a fixed charge (including the residual element) and capacity charge derived from the first step above to each embedded customer for both import and export charges. St Clements' understanding is that the use of the Settlement metering data to determine the power flow data at the boundary and then the subsequent allocation of a fixed charge relates to how the tariff itself is calculated and that there will be no change to how the sites are billed. The tariffs will have the capacity charges combined with the fixed charge, hence the tariff itself will only have unit charges and fixed charges. Assuming this is the case DURABILL is able to bill such tariffs and control reports such as the Missing Tariff and MIC report since they are already configured to allow for this type of tariff. St Clements assumes that the Settlements metering data will be available in DURABILL if DNOs wish to use it to support the tariff setting process. We would anticipate that this data will be used by DNOs via their own reporting solutions and is therefore outside of the scope of work that St Clements will carry out.	Working Group agree with the respondents comments with respect to DURABILL

SSE Generation	Non-confidential	We consider the process set out in attachment 6 for fully settled arrangements under the EDCM sensible and workable.	Noted - consider the process sensible and workable
The Electricity Network Company Limited	Non-confidential	We do not have any comments on the EDCM solution.	Noted
UK Power Networks	Non-confidential	No we don't have anything to comment or add to the EDCM solution.	Noted
Western Power Distribution	Non-confidential	No comments	Noted

Company	**Confidential / Anonymous**	**4. Do you have any comments on the rebate solution?**	
Emergent Energy Systems Ltd.	Non-confidential	n/a	-
Electricity North West	Non-confidential	It does not appear that the sum of the charges to embedded customers less the rebate to the PNO would necessarily equal the equivalent charge that would be levied on a single customer, with the same connection and usage as the PNO. Therefore, we do not consider this to be an acceptable solution. In the case of reactive power charges, say, we don't believe that the total charged (i.e. the sum of the customer charges less the rebate) would be the same as for the same situation where a customer has charges based on readings from a boundary meter. This is because reactive units would be netted at the boundary for charging purposes.	do not consider this to be an acceptable solution. WG were aware that equivalent charge wouldn't be completely seen and thus were aiming for the best…… However, concerns remain with respect to fairness of the charges for PNOs.

ESP Electricity Limited	Non-confidential	We have some concerns on the rebate solution. Firstly, PNOs are not a party to DCUSA. Implementing a formal process for charging of UoS charges is more involved that network unavailability payments referred in the consultation – particularly as the chances of disputes for charging are likely to be higher and it is unclear whether PNOs would simply be treated as regular customers for the purpose of the DCUSA dispute process. Secondly, while we recognise that any under or over recovery can be corrected in subsequent years, we question whether there is a positive trade-off for the increased fluctuation to year-on-year charges compared to the tariff solution (Solution B).	Concern related on the rebate solution. WG note the concern around dispute process and has been mentioned in other responses
Northern Powergrid	Non-confidential	This option maintains the standard arrangements between DNOs and suppliers, with suppliers invoiced as though the customer were connected to the distribution network. Hence, it will minimise implementation and ongoing costs, thus avoiding creating barriers to competition in supply. PNOs would have the option to claim some use of system revenue from the distributor. In reality, we would expect that only large PNOs would do so, as the PNO to DNO claim is likely to be immaterial for smaller private networks. We agree that, if introduced, the mechanism by which the amount of use of system revenue the PNO can claim from the DNO should be defined and applied consistently. This cannot be formalised in the DCUSA as PNOs are not DCUSA parties, but we welcome the publication of guidance within Schedule 16 and the LC14 which sets out how the calculation should be carried out (akin to that used for distributed generation network unavailability (DGNU) rebate payments). Whilst not binding, this guidance could then form the basis of common bilateral arrangements between DNOs and PNOs, improving transparency and commonality.	Noted (supportive comments)
Power Data Associates Ltd	Non-confidential	Rebate solution is preferred. It is simple to administer by Suppliers in offering customer prices. It allows a PNO to apply if it is worthwhile. It enables the DNO to become aware of the PNOs existence for connection agreement and engineering interface purposes, as required in the ESQCR.	Noted (supportive comments)
Scottish Hydro Electric Power Distribution plc and Southern	Non-confidential	It's an interesting concept that assists with the overall solution to the problem DCP 328 seeks to resolve: it should therefore be considered in that context. However, it seems that it will carry a significant administrative burden and that must be explored further.	Comment around significant administrative burden based on DGNU rebate expereince

Electric Power Distribution plc			
ScottishPower Energy Retail Ltd	Non-confidential	No	Noted
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	Under solution A, PNOs would be able to claim a rebate from DNOs for the element of DUoS in respect of assets on their network. This applies to fully settled systems only. It is likely that DURABILL could be enhanced to calculate and produce the PNO credit. Costs for such a development would be in the region of £80,000 to £150,000 split between all DURABILL customers. As well as the new processes required to calculate the rebate some changes to existing standing screens such as the MPAN registration and Maintain a Site screen are likely to be required. Some of these changes are likely to also be required to support the calculation of boundary meter data for difference metering and shared systems as per the response to question 2. If both are progressed the total cost to implement is likely to be slightly less than the sum of the two cost estimates given in response to question 2 and this question. SCS assumes that DNOs will require changes to their finance interface packages as it's likely that the PNO credit will need to be accounted for differently to DUoS bills. For DNOs who have a finance interface procedure in DURABILL, the costs to change would be in the region of £30,000 each. **These costs are considerable for the DNOs to accommodate the rebate solution.** The rebate is likely to be small in value and volume of PNO. Could a rebate be calculated in a less complicated formula to make the creation of the rebate much easier for the DNO. Could the annual total kWH recorded at the boundary meter be applied to a rate to this to calculate an annual rebate, or a similar simple formula?	Question related to what the 'rate' would be and whether this would be cost reflective. It should be possible to calculate outside of DURABILL and this could be calculated by the PNO and invoiced to the DNO/IDNO but this may require verification. Question on how easy it would be to verify the invoiced rebate amount. Also, how to ensure all PNOs use consistent process.

			Could be facilitated within the LC14 statements and included in connection agreements. Question related to whether such a solution is out of scope of the changes being progressed under DCP328.
SSE Generation	Non-confidential	We are concerned about the complexity of the rebate solution (A) and some of its outcomes, including the need to mitigate for the various flaws in this solution. a) We are concerned that the proposed modelling approach results in bills for some customers, namely those HH Aggregated customers whose volumes are higher or lower than the average for their customer group, being slightly lower or higher than for customers with average volumes, making some customers worse off under solution A. We note that the proposed solution is to cap the rebate so that Private Networks (PNs) would not be liable for more DUoS than if they were directly DNO-connected but we consider this sub-optimal. b) We note that there are no provisions to ensure that any rebate the PN receives is actually passed on to PN customers, so there is no mechanism to ensure that PN customers' DUoS bill would be the same, whether distribution or PN connected. Whilst we acknowledge that this is out of scope, as PNs and their customers are not DCUSA parties, we think that this is not satisfactory. c) We are concerned that the rebate solution would result in DNOs under-recovering their allowed revenue (although we don't feel it is clear why that would be the case). We do not see that the proposed solution of socialising this shortfall across the charging base the following year (estimated to be -0.05% and -0.12% of baseline revenue) is justifiable. As a result of these various concerns, we don't consider that this is the better approach of the two options put forward. If the rebate solution was to be approved, then we would advocate that PNs have access to the set of bespoke tariffs, and that this is spelt out in the legal text. This would enable PNs to assess, in advance, the likely size of the rebate they might be eligible for, and whether submitting a rebate application would result in a net gain or a net cost to them, once they have taken into account the costs of additional metering and of process-related costs, including those of the TO which would be passed to the PN.	Note the concern about the complexity. The issue in (a) could be due to customers with high load factor will lose and vice versa. Results from the capacity charge being pushed into the fixed charge.

Commented [DT2]: Draw out main items

The Electricity Network Company Limited	Non-confidential	Yes. We have split our comments on the rebate solution into two areas, those which are specific to the rebate solution and those which we think equally apply to the tariff solution. <u>Rebate solution specific comments</u> We question the merits of this solution. We do not believe that applying a rebate directly to a private network operator is an appropriate solution. Use of System charges are made to suppliers in accordance with the provisions in DCUSA and so to rebate the private network operator (the party who has not paid the original charge) may lead to unsatisfactory outcomes. If our understanding of paragraphs 4.51 to 4.53 is correct, the rebate is on the premise is that: • distributor is charging the supplier the all the way charge to the relevant supplier, that is to say, a use of system charge for both the licensed distribution network and the private network; • the distributor is then paying an amount to the PNO in respect of the network he provides, i.e. a rebate. Give that the private network operator has not paid the initial use of charge, then how can they rebated for something they hasn't paid? For example, if a supplier is charged £x for use of system by the DNO/IDNO where they supply a customer connected to a private network they will 'need' to recover that cost from the customer as part of the customer's supply tariff. The customer is likely, therefore, to pay for an electricity supply as if they were connected to licensed network operator's system. It is unclear that customers will benefit from any rebate which is provided to the private network operator. It is outside the vires of DCUSA to determine the arrangements that are in place between the end customer and the private network operator (such end customer has no relationship with the licensed distributor (except and to the extent that the NTCs may have been procured by the relevant supplier and may apply in respect of such customers use of the upstream network) We also believe that using the rebate solution brings about unnecessary contractual issues. The calculation of the rebate is likely to be 'governed' by the CDCM and will sit within the DCUSA. Private network operators are not a party to the DCUSA and, as such, would have no mechanisms by which they could seek to change the methodology for calculating the tariffs without leave being granted by Ofgem or a DCUSA party agreeing to raise it on their behalf. It is also unclear that the contractual relationship between the distributors and the private network operators will provide a robust mechanism to administer the rebate. We note that, in the absence of bespoke terms, the NTCs will	

		apply to the boundary meter but this change proposal does not include changes to the NTCs so it is unclear if consistent terms would be applied to the private network operators in all instances. <u>Rebate/tariff calculation comments</u> We do not believe that the method by which the rebate (for the purposes of this response we will use the term rebate but comments will equally apply to the specific tariff under the alternative option) have been calculated meet the purpose of the change proposal, namely "…to ensure that use of system charging remains cost-reflective when competition in supply on a private network is in place". The all-the-way tariffs calculated by the charging methodologies are designed to be costs reflective and also incentivise behaviour from customers. In the CDCM the 500MW model is intended to be representative of the DNO's existing distribution system insofar as assets and typography are concerned but it does not include realistic full costs for installing that size increment (i.e. full excavation and reinstatement) and does not consider the full cost of operating and maintaining that network (i.e. only 60% of indirect opex is included and reinforcement and replacement are excluded). Using the "forward-looking" element of the methodology (i.e. the 500MW model costs) to drive the calculation of the tariff cannot, therefore, be considered to be a cost reflective methodology for calculating rebates/tariffs. The all-the-way tariffs are corrected by virtue of scaling which ensures that the DNO is able to recover the full, efficient, costs associated with operating a distribution system (as determined by Ofgem in their price control). Whilst it is recognised that the scaling element, either as a scaled unit rate, a fixed p/kWh adder or a fixed p/MPAN/day adder, is not intended to be representative of a specific set of costs but it does, to an extent, increase cost reflectivity of the tariffs because it ensures that the tariffs recover costs. It should, therefore, be the all-the-way tariff which should be the starting point to calculating a cost-reflective rebate (such as is calculated by virtue of the PCDM for LDNO tariffs). One further issue with use of the forward-looking element to drive the calculation of the rebate tariff is that the costs which are excluded are not excluded 'evenly' across the different tariff elements. Although we do not have an exhaustive list of tariffs across all DNO areas we reference tariffs which were shared by NPg having populated the revised models on 13th May 2021. This document shows, for example, that LV LES Domestic Aggregated tariff excludes charges solely from the fixed p/MPAN/day element of the	

		tariff. One of the desired outcomes from this change proposal (as referenced in paragraph 1.8 of the consultation) is that there should be "equivalence in charges" where there is competition on supply compared to where there is a single supplier. Calculating charges based on the forward-looking element of the tariff such that charges are 'removed' from a single element of the tariff (or heavily taken from that element in the case of an HV connected LES) cannot be seen to meet this desired outcome. We have further concerns with the approach in respect of removing charges from the fixed element of the tariffs which are addressed in questions 11 and 12 (on the methodology for residual charges and LDNO impacts respectively). The calculation of a rebate/tariff must take into account the total avoided costs and also reflect the services that are provided to the PNO under the DNO's licence. As we have stated earlier, we do not believe that the use of the 500MW model to drive the calculation of the tariff is cost reflective. We also think that this does not adequately take into account either the total avoided cost or services provided to the PNO. The determination of the avoided cost is driven by the variable avoided costs (i.e. the network tiers which the PNO replaces) which will include direct operating costs and some indirect cost. However, the exclusion of some indirect costs and no assessment of deliberately attributing the residual element to activities undertaken by the PNO means that the tariffs are unlikely to properly consider the fixed costs faced by a PNO and may mean that they are non-compliant with Chapter II of the Competition Act.	
UK Power Networks	Non-confidential	The rebate solution adds additional complexity and would add significant administration costs as well as not following or mirroring any existing arrangement, as a result we do not believe that it would be appropriate to utilise this solution. As the DNO we would also be unlikely to have visibility of who is actually entitled to the rebate over time.	additional complexity and would add significant administration costs don't believe to be appropriate
Western Power Distribution	Non-confidential	WPD do not believe that the rebate solution is sensible as there will be a delay to the private network receiving their discount and it will add additional complication to the billing systems. WPD would prefer the solution that has a new set of tariffs for private networks. If the rebate solution is adopted it will need to come straight off RDt (regulated revenue), although, as mentioned before, by the nature of how this will be paid there is likely to be a delay which means that rebates for 1 year will be paid out of the RDt of the following year.	do not believe that the rebate solution is sensible
Numerous comments (to be drawn out in Change Report) generally speaking it seemed that there were a lot of concerns however some supportive comments were also noted			

Company	Confidential / Anonymous	5. What are your thoughts on customers that export within the PNO Network, should there be a negative rebate?	
Emergent Energy Systems Ltd.	Non-confidential	n/a	-
Electricity North West	Non-confidential	We believe that negative rebates may be problematic as DNOs might rely on PNOs to identify export sites embedded in PNO networks, however not having negative rebates creates distortions in competition. Regarding customers that have export MPANs, having no negative rebate to PNOs for any export MPANs could result in a distortion to competition with generators that connect at the same voltage as the PNO. This is because the aggregate of credits to an LV generator on an HV PNO network and the rebate (ie zero) to that HV PNO network would be higher than the credit paid to a generator connected at HV.	
ESP Electricity Limited	Non-confidential	We note that the logical conclusion for import customers receiving a positive rebate is that export customers face a negative rebate but the economic rationale in support or opposition has not been provided in this consultation. Additionally, a negative rebate adds further complexity as the distributors would be a in a position to charge some PNO customers which again raises concerns from a code participation perspective.	
Northern Powergrid	Non-confidential	The impact assessment shows that any negative rebate for export would be small on a per MPAN basis. The rebate solution relies on PNOs applying for a rebate and it is unlikely that they would apply for a negative rebate (i.e. a charge). In addition, as PNOs are not party to DCUSA there would be no obligation for them to pay the negative rebate to the DNO/IDNO Party. Based on this it is our opinion that there should not be a negative rebate for export customers within the PNO Network.	
Power Data Associates Ltd	Non-confidential	No – too difficult to determine and administer. Particularly when there are demand customers actually consuming the power within the PNO.	**
Scottish Hydro Electric Power	Non-confidential	A negative rebate: a charge to the PNO. Presumably based on the assumption that the units (kWh) generated won't leave the PNO network? Like all current Generation Credits	

Distribution plc and Southern Electric Power Distribution plc		this would be unable to take account of the network load and would be applied without regard to generation dominated area, or network congestion considerations.	
ScottishPower Energy Retail Ltd	Non-confidential	Understand how Working Group reached their determination and agree with it.	Noted and support approach of WG (i.e. no negative rebate)
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	A rebate is defined a refund, so a negative rebate is a contradiction in term. SPEN agree with the working groups decision to not levy a negative rebate (i.e charge) to PNOs for any export MPANs.	Noted and support approach of WG (i.e. no negative rebate)
SSE Generation	Non-confidential	We note that the Working Group is proposing that there would be no negative rebate (i.e. charge) to Private Network Operators (PNOs) for any exporting MPANs. We would like clarity on how this compares to the scenario where exporting users are connected directly to the distribution network, given the premise of the proposal is equivalence of charges.	Capture in Change Report
The Electricity Network Company Limited	Non-confidential	In principle we agree that the rebate should be floored so that a negative rebate does not apply	Noted and support approach of WG (i.e. no negative rebate)
UK Power Networks	Non-confidential	As stated in response to Q4, we do not support the rebate option, but if it was to proceed then it would also be necessary to have negative rebates, but this would create a further un-necessary set of arrangements. In addition where is the obligation on the Private Network to pay these negative rebate charges, as these parties are not a signatory to DCUSA this would likely be impossible to successfully implement.	Noted that doesn't support rebate approach and therefore doesn't support the premise of negative rebates
Western Power Distribution	Non-confidential	It should be noted that for portfolio IDNO customers IDNOs that are HV and LV connected do not have a discount but the EHV connected IDNOs do.	Links to equivalence of approach between current (IDNOs) and this change for PNOs. i.e. if floored or no discount then no negative rebate

[summary to be added]

Company	Confidential / Anonymous	6. Do you agree that the rebate process should be added to Schedule 16? And if so, do you have any suggestions on the process to improve it?	
Emergent Energy Systems Ltd.	Non-confidential	n/a	-
Electricity North West	Non-confidential	If rebates are to be regarded as non-DUoS, it may be better for them to be covered in a separate schedule.	Not supportive of rebate process in Schedule 16
ESP Electricity Limited	Non-confidential	We support solution B and thus, do not support the addition of the rebate process to Schedule 16.	Not supportive of rebate process and therefore not supportive of rebate process in Schedule 16
Northern Powergrid	Non-confidential	We agree that, if introduced, the mechanism by which the amount of use of system revenue the PNO can claim from the DNO should be defined and applied consistently. This cannot be formalised in the DCUSA as PNOs are not DCUSA parties, but we welcome the publication of guidance within Schedule 16 and the LC14 which sets out how the calculation should be carried out (akin to that used for distributed generation network unavailability (DGNU) rebate payments). Whilst not binding, this guidance could then form the basis of common bilateral arrangements between DNOs and PNOs, improving transparency and commonality.	[pick up later]
Power Data Associates Ltd	Non-confidential	What is proposed makes sense	supportive
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	Adding a rebate process in Schedule 16 might be useful; and would obligate the DNO and Supplier Parties. It's not quite clear what the relationship/contractual arrangements would have to be in place between the PNO & their Supplier.	Potentially supportive

ScottishPower Energy Retail Ltd	Non-confidential	We agree that is should be documented within DCUSA but have no preference where.	No preference
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	Yes, even though PNOs are not party to DCUSA, there is a need to be some transparency and visibility off the rebate process, especially if solution A is adopted where PNOs are required to opt-in if they are to receive a rebate. One aspect not covered in the proposed solution detailed in the consultation document is how DNOs should handle replacement meter reads. If significantly different meter reads are received after the point when the rebate is calculated and issued to the PNO should the DNO be obligated to issue a new rebate? If so, should this be an adjustment or a full cancellation and rebill?	Supportive Process for this may need to be included (WG to consider)
SSE Generation	Non-confidential	We do not favour the rebate solution (A) but if this was the option to be approved, we would agree that the process should be formalised in Schedule 16. However, given that PNOs are neither licensed, nor DCUSA parties, we are not convinced that this provision would be sufficient to alert PNOs to the fact that they might be eligible for a rebate, so we would advocate that DNOs use additional means to raise awareness.	Not supportive of rebate process but supportive of rebate process in Schedule 16 with some concerns
The Electricity Network Company Limited	Non-confidential	Whilst we do see some merit in the provision of some text outlining the process for determining the rebate we do not believe that Schedule 16 is the appropriate place to include it. We believe that the process for claiming rebates should be contained within the charging statements (LC14 statement) published each year by distributors.	No supportive of inclusion in Schedule 16 Proposal to include in LC14 statement and noted that this had been mentioned earlier as well (WG to consider)
UK Power Networks	Non-confidential	As stated in Q4 we do not support the rebate approach, but if it was taken forward then schedule 16 would seem appropriate, other than the points raised in response to Q5. We do not have any further thoughts at this stage to improve the process.	Not supportive of rebate process but supportive of rebate process in Schedule 16 with some concerns
Western Power Distribution	Non-confidential	If the re-bate solution is adopted then it will be sensible to include in schedule 16 of DCUSA.	Not supportive of rebate process but supportive of rebate process in Schedule 16 with some concerns

Noted a number of alternative suggestions that the working group will consider further if rebate solution was to be progressed

Company	Confidential / Anonymous	7. Do you agree the rebate should be billed annually? If not, please provide reasons.	
Emergent Energy Systems Ltd.	Non-confidential	n/a	-
Electricity North West	Non-confidential	Yes, if this solution is selected. Consideration needs to be given as to when the final settlement data is available including through all industry settlement runs.	agree the rebate should be billed annually (if rebate solution is chosen)
ESP Electricity Limited	Non-confidential	We support, in principle, the billing of the rebate as an annual process.	agree the rebate should be billed annually
Northern Powergrid	Non-confidential	Yes - the impact assessment shows that the rebates will be relatively small per MPAN. It would be administratively more efficient for all parties to bill the rebates annually, rather than more regularly. This would put the process in line with the DGNU rebate process (which although a completely different process is comparative in magnitude and administrative burden).	agree the rebate should be billed annually
Power Data Associates Ltd	Non-confidential	Yes, for administrative simplicity	agree the rebate should be billed annually
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	There are parallels with the DGNUR scheme involves annual billing, after 31 March each year.	agree the rebate should be billed annually
ScottishPower Energy Retail Ltd	Non-confidential	Seems a sensible and efficient option.	agree the rebate should be billed annually

SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	Yes, Were the rebate to be calculated in and produced from DURABILL it shouldn't make a difference whether the rebate is calculated monthly or annually. However if the rebate is calculated annually this reduces the risk of inaccuracies in the meter data impacting on the rebate value as a significant proportion of the reads will have already gone through several reconciliation runs.	agree the rebate should be billed annually
SSE Generation	Non-confidential	The billing frequency should be proportionate to the administrative burden on DNOs and PNs, and to the likely size of the rebates.	Noted (agree the rebate should be billed annually)
The Electricity Network Company Limited	Non-confidential	Yes, this is likely to be the most proportionate solution for all parties involved. However, we do not think that the DCUSA can or should mandate this as it should be for distributors to determine, in consultation with their private network operator connected customers, the appropriate timeline for rebates (again, we would sooner see this outlined it the LC14 statements). As earlier noted, we do not believe that it is necessarily appropriate to describe a process in the DCUSA where the party to which is applies has no mechanism to change or challenge it.	agree the rebate should be billed annually but additional considerations set out
UK Power Networks	Non-confidential	Any individual rebate would likely to be small, but there could be many sites which would be eligible, as a result an annual process would be the most appropriate frequency.	agree the rebate should be billed annually
Western Power Distribution	Non-confidential	If the re-bate solution is adopted then if it is built automatically in the Durabill system then an annual bill is likely to easier administratively, however as PNOs are not signed up to DCUSA setting up a time framework for them to follow to claim could be difficult to enforce. Thought should be given to whether third party networks should be signed up to DCUSA.	agree the rebate should be billed annually if rebate solution is taken forward
Agreement that the rebate should be billed annually if rebate solution is taken forward			

Company	**Confidential / Anonymous**	**8. Do you have any comments on the tariff solution for fully settled metering installations?'**	
Emergent Energy Systems Ltd.	Non-confidential	n/a	-

Electricity North West	Non-confidential	Aggregate DUoS charges should be identical under all scenarios including no competition in supply or a single site/customer. We do not believe this would be achieved by the tariff solution for fully settled metering installations. As part of the role of the private network owner, and to enable competition, we suggest PNOs could be asked to identify which customers are on their networks and industry processes could then be put in to place to create pseudo boundary meter data that could be used to bill an appointed supplier DUoS. The benefit of this solution is that it ensures that the DUoS charges to the DNO are the same under all metering arrangements.	Doesn't believe the tariff solution provides for identical Aggregate DUoS charges
ESP Electricity Limited	Non-confidential	No comments.	
Northern Powergrid	Non-confidential	This solution introduces a significant number of new tariffs (96 CDCM tariffs per DNO, 1,344 (96x14) CDCM tariffs per IDNO). Given that the number of MPANs connected to private networks is relatively small this would seem to introduce a disproportionate level of complexity to the charging structure and billing process. It also creates an administrative burden for suppliers and DNOs, which increases the costs to serve embedded customers. The conversion of the capacity charge to a fixed charge seems to be a reasonable and proportionate approach to allocating capacity charge to embedded MPANs without requiring additional information from the PNO.	
Power Data Associates Ltd	Non-confidential	Very difficult to administer. Currently DNOS state that they have little knowledge of fully settled customers, although they include them in the registration system and issue MPANs.	Noted comments provided
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	No	Noted no comments
ScottishPower Energy Retail Ltd	Non-confidential	Do not agree that a supplier MUST change a customer's tariff – it will be fully dependent on what the customer wishes AND what the current contract allows for.	Noted comments related to

SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	DURABILL would be able to bill sites based upon the tariff described in the consultation document without any system changes being required.	Noted the comment related to use of DURABILL system
SSE Generation	Non-confidential	See also our responses to q.7 and q.9.	Respondent clarified only q9 is relevant
The Electricity Network Company Limited	Non-confidential	The comments which we have provided in answer to Question 4, under the heading 'rebate/tariff calculation comments' are relevant to the tariff solution for fully settled metering. We will not reiterate those points here but do provide some points which are specific to Solution B. One of the barriers that this solution faces which we believe further consideration is the way which the tariffs are allocated to MPANs within distributors' billing systems. Presently this is, generally, through the application of the LLFC. Experience through the targeted charging review has shown that the creation of LLFCs and the associated data required (SSC, MTC and PC for example) is an incredibly burdensome task with repercussions throughout the industry for parties required to load the data into their systems. Increasing the number of tariffs from 32 to c.107 (based on the number of tariffs included in the NPg summary mentioned earlier) will be difficult to implement under the current market framework. The alternative solution might be to use the MTC to identify where a customer is connected to a private network operator's system, but we believe that this is likely to require changes to our billing system which will have both cost and lead time implications for the change (both of which can be quantified on request).	Consideration to be given to alternative solution, however, noted that it is worth checking impacts of MHHS to MTC
UK Power Networks	Non-confidential	No.	Noted
Western Power Distribution	Non-confidential	No comments	Noted
Comments to be drawn out in change report			

Company	**Confidential /**	**9. Which solution do you support and why? Solution A or Solution B.**	

	Anonymous		
Emergent Energy Systems Ltd.	Non-confidential	n/a	
Electricity North West	Non-confidential	We do not support either solution as they do not achieve the objective that Aggregate DUoS charges should be identical under all scenarios including no competition in supply or a single site/customer.	
ESP Electricity Limited	Non-confidential	We support solution B. The rebate solution presents some issues (outlined in questions 4. And 5.) and we perceive the tariff solution to be more simplistic to implement and utilise.	
Northern Powergrid	Non-confidential	We support Solution A (rebate for fully settled metering in the CDCM). For the CDCM the rebate solution offers a simpler solution than the new tariffs solution. This solution maintains the standard arrangements between a DNO/IDNO party and suppliers, with suppliers invoiced as though the customer were connected to the distribution network. Hence, it will minimise implementation and ongoing costs, thus avoiding creating barriers to competition in supply. Solution B would introduce 96 (3 boundaries x 32 tariffs) new CDCM tariffs and corresponding LLFCs per DNO, with IDNOs requiring an additional 1,344 (96x14) new CDCM tariffs each. This seems disproportionate to the benefit from introducing these tariffs as there are relatively few MPANs which these tariffs would serve. In addition, a DNO/IDNO Party may not be able to easily identify which customers are connected to private networks without the PNOs identifying themselves. Solution A requires that the PNOs request the rebate from the DNO, thereby identifying themselves and allowing a DNO/IDNO Party to request any additional information required. Solution B requires a DNO/IDNO Party to already have knowledge of which MPANs belong to PNOs in order to assign those MPANs to the correct tariffs.	
Power Data Associates Ltd	Non-confidential	Solution A. For reasons above	
Scottish Hydro Electric Power Distribution plc	Non-confidential	Either would work – no preference at this time	

and Southern Electric Power Distribution plc			
ScottishPower Energy Retail Ltd	Non-confidential	No real preference, as above – it has to be cost effective, efficient and easy to understand for all involved.	
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	Option B, since this involves directly billing the supplier with no need to rebate the PNO and has the least impact on under and over recovery, which could become larger as more PNOs connect to the distribution network. This option also removes the unfair application of rebates, as it does not rely upon CDCM PNO's opting-in and will be applied to all.	
SSE Generation	Non-confidential	Given the complexity of the fully settled metering solutions under the CDCM, we would have welcomed worked examples for solutions A and B, for greater clarity and transparency (as was usefully provided in Attachment 6 of the consultation for the EDCM solution). Based on our understanding as it stands, we favour solution B over solution A for the CDCM solution for fully settled metering arrangements. This is because under solution B: a) PN customers benefit directly through the bespoke tariffs that their supplier will charge them, whereas under solution A, where a rebate is paid directly to the PN, there is no mechanism that ensures that PN customers receive a benefit. b) The administrative burden for both the DNOs and the PNOs appears to be lighter than for solution A. c) There is no year-long wait for the financial benefit. a) Having said that, we are concerned that solution B, like solution A, would result in DNOs under-recovering their allowed revenue (although we don't feel it is clear why that would be the case). We do not see that the proposed solution of socialising this shortfall across the charging base the following year (estimated to be +/- 0.01% of baseline revenue, i.e. smaller than the estimated shortfall under solution A) is justifiable.	
The Electricity Network Company Limited	Non-confidential	We do not support either solution on the basis that we believe that the methodology used to calculate the tariff in each instance is fundamentally incorrect and leads to too many undesired, and avoidable, consequences.	

UK Power Networks	Non-confidential	Solution B, for the reasons stated above relating to un-necessary complexity and increased costs.	
Western Power Distribution	Non-confidential	WPD support Solution B as this will adjust billing to the private networks in at source and therefore will be simpler and allow real time discounts as billing occurs. This will require the private network customers to have new LLFCs.	

Company	**Confidential / Anonymous**	**10. Do you agree with the approach to consider complex site based on the definitions agreed in DCP359?**	
Emergent Energy Systems Ltd.	Non-confidential	n/a	
Electricity North West	Non-confidential	Yes, this change proposal may interact with DCP 388. In addition, the solution will need to support the requirement to report a single site under P402 to enable TNUoS billing. The Working Group should also consider that the site remains a single site for the purposes of the TCR.	
ESP Electricity Limited	Non-confidential	Yes, we agree that complex sites can be covered under the definitions created and implemented under DCP359.	
Northern Powergrid	Non-confidential	Yes - the definition of complex site agreed for DCP359 is the definition that has been approved and should be considered here. Potential future changes to the definition arising due to DCP388 should not (and cannot) be taken into account.	
Power Data Associates Ltd	Non-confidential	Yes – complex sites is not a well defined term	
Scottish Hydro Electric Power Distribution plc and Southern	Non-confidential	Yes	

Electric Power Distribution plc			
ScottishPower Energy Retail Ltd	Non-confidential	Yes	
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	Yes.	
SSE Generation	Non-confidential	Yes, we do.	
The Electricity Network Company Limited	Non-confidential	Yes, we agree with this approach as we do not believe that the framework presently exists (i.e. contractual arrangements between distributor and private network operator connected customer) to consider differently.	
UK Power Networks	Non-confidential	Yes, this was developed over lengthy discussions and is felt to be representative.	
Western Power Distribution	Non-confidential	If a private network has 4 generators and 1 demand site all metered separately and with their own assigned import and export capacities should the 4 generators be treated as non-final demand and the 1 demand site be treated as final demand. DCP359 treats them all as final demand if they have one connection agreement.	

Company	**Confidential / Anonymous**	**11. Do you agree with the proposed methodology for calculating residual charges? If not, please provide your rationale.**	
Emergent Energy Systems Ltd.	Non-confidential	n/a	

Electricity North West	Non-confidential	Our view is that overall residual charges should be unaffected in comparison with a single site with a boundary meter.	
ESP Electricity Limited	Non-confidential	Yes, we support the proposed methodology for calculating residual charges.	
Northern Powergrid	Non-confidential	Yes - for EDCM customers the methodology ensures that the same residual is being recovered with and without competition in supply, and for CDCM customers it ensures the same scaling is applied to all aspects of the charge (both forward looking and residual), which would seem to be the fairest approach. We agree that compliance with the TCR can only be achieved (at least in a practical and proportionate manner) by considering the private network as a Single Site, given we do not have agreements with sites behind the private network and to avoid risk of other customers on the same network paying more. We believe that this is a necessary 'compromise', where we recognise Ofgem's position that sites connected within a private network should be treated on equivalent basis as a 'standard site' (albeit this position was explicitly set out in the context of transmission-connected sites in the Authority's decision on CMP334).	
Power Data Associates Ltd	Non-confidential	Yes – I defer to the greater knowledge on the working group. But the intention was to rebate to the PNO to costs relevant to their proportion of the distribution network.	
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	Yes – it looks okay	
ScottishPower Energy Retail Ltd	Non-confidential	Yes	
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	Yes.	

SSE Generation	Non-confidential	We have no specific comments.	
The Electricity Network Company Limited	Non-confidential	No, as we have previously stated in our response to question 4 we do not believe that it is appropriate for the calculation of residual charge applicable to customers connected to licence exempt systems should be driven by the forward-looking element of the charge. Using the ratio by which the all the way charge has been reduced is also likely to be floored as that reduction will be different for different customers depending on their consumption (if a customer uses fewer units then the proportionate impact of a reduction in the fixed elements of their tariff will be greater whereas a customer using more units will see the bill for their use of system reduced by a lower proportion). We believe that the only solution which can properly consider to allocate the residual charge is to take a top down, total cost approach akin to the current methodology in the PCDM.	
UK Power Networks	Non-confidential	Yes.	
Western Power Distribution	Non-confidential	Yes	

Company	**Confidential / Anonymous**	**12. Are there any unintended consequences associated with either solution with consideration given to any impact on Independent Distribution Network Operators?**	
Emergent Energy Systems Ltd.	Non-confidential	n/a	
Electricity North West	Non-confidential	We do not believe the solutions will impact IDNO tariffs. Further work may be needed to investigate arrangements for PNOs connected to IDNOs, or vice versa.	

ESP Electricity Limited	Non-confidential	We have not identified any direct unintended consequences on IDNOs at this time but are disappointed with the lack of clarity for certain aspects and would hope that they are addressed comprehensively before finalising this CP. The impact assessment and workgroup do not seem to have undertaken an assessment on the impacts of the options on the LDNO tariffs. Given that these tariffs are provided by the PCDM which uses a fixed and static methodology of cost allocation, it would seem that there's a mismatch between the cost allocation used to provide the LDNO discount % and the calculation of the PNO rebate or tariff (which removes LV costs). Additionally, we would question whether the new methodology for UoS charges to PNOs does not restrict margins for IDNOs and allows IDNOs to competitively bid for private network sites i.e., IDNOs would earn the same margin as that of the upstream DNO on a notional equivalent. Therefore, we think there is still an element of competition law that should be considered by the workgroup and Panel in its assessment of this CP. Lastly, it is not clear how the charging mechanism would work in embedded networks, for example, where the network comprises of a DNO, an IDNO and a PN connected to the IDNO network as it would appear the DNO would charge/rebate the PN directly.	
Northern Powergrid	Non-confidential	None that we are currently aware of. The number of private networks embedded within IDNO networks is likely to be small which should make any impacts for IDNOs minimal, subject to the implementation solution.	
Power Data Associates Ltd	Non-confidential	Not that I can determine	
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	None that we are aware of or have identified in this Consultation documentation	
ScottishPower Energy Retail Ltd	Non-confidential	None we are aware of	

SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	Option A relies upon a PNO to opt in, although this will provide visibility of who the PNOs are, this will need the PNO to be proactive, hindered the uptake, option B removes this complication.	
SSE Generation	Non-confidential	We have no comment on unintended consequences in relation to IDNOs.	
The Electricity Network Company Limited	Non-confidential	Yes, we have three main concerns in respect of both solutions which will have unintended consequences on IDNOs 1. It is unclear from the legal text what tariff will be applied to an IDNO where an end customer is connected to the DNO via both an IDNO and private network. Taking the following scenario, a private network operator system serves a block of flats (all domestic). That private network operator connects to an IDNO's network at LV. The IDNO, in turn, connects to the DNO at LV. We take the current reading of the legal text to mean that the tariff which will be applied to the IDNO, by the DNO, is the LDNO LV:Domestic Aggregated tariff. However, we think some consideration should be given by the working group about whether the tariff which should be applied would be the "LDNO LV: Licence Exempt System Tariffs – LV Connection LV Domestic Aggregated". That is to say we wish the working group to consider the application of the LDNO tariff discount factors, as calculated under Schedule 29 to licence exempt tariff set such that the IDNO would be charged a tariff discounted from a different starting point (the LES tariff) that would normally apply if the IDNO owned the connection to the customer. This issue is particularly prevalent for solution B as the data will flow through industry systems and processes, but we also believe it should be considered for option A where the portfolio billing between DNOs and IDNOs will not be dependent on rebates being sought. 2. Both solutions may lead to margin squeeze on LDNO networks which is likely to be worse if point 1 is not addressed. We are working under the assumption that the tariffs for fully settled sites (under both options) are likely to be applied to customers who are connected to licence exempt networks via IDNO or DNO out of area networks under Special Condition BA3 of the IDNO licence which demands equivalency of charges for Domestic Customers. (i.e. DNO will charge the LDNO and the LDNO will charge the supplier based on the LES tariff). This will reduce the margin available to the IDNO where it provides connections to licence exempt systems. Whilst we understand that this is an inevitable outcome of this change proposal (insofar as the IDNO is avoiding some of the costs associated with the provision of end connections) we do not believe that the current solution has adequately	

		considered the implications on IDNO margins. We are unable to take a full assessment of impacts because we do not have full tariffs available but have undertaken a crude assessment from the data circulated by NPg. Using the estimates and averages for consumption which were contained in the summary circulated by NPg, in the above scenario where the LES connects to the IDNO at LV and the IDNO to the DNO at LV the rebate/margin available to the private network operator is £28.64 per customer whereas the margin available to the IDNO is £11.79 per customer. If the IDNO owned the whole network then the margin available to the IDNO would be £40.43 (i.e. the combination of LES and IDNO margins). Due to the way that the LES tariffs are calculated (the LES gets a big discount on the fixed charge and the unit rates are barely, if at all, reduced) where a customer reduces their consumption the margin available to the IDNO reduces but the margin available to the LES generally does not. Many private networks are contained within blocks of flats and it is a reasonable assumption to say that the consumption within a flat is markedly lower than the average domestic customer. If the consumption were to half for a customer on the above scenario then the margin available to the private network operator would still be £28.64 but the margin available to the IDNO would be £4.10. It is not for us to determine whether or not the tariffs calculated by this change proposal are compliant with competition law as we are not able to undertake the requisite AEC test. However, we would find it incredibly difficult to believe that the notional downstream DNO business could operate effectively and without cross subsidy on a margin of £4.10 given that many of the costs associated with the provision of MPAS, billing, industry systems, licence or code fees will still be borne by that notional downstream DNO business. 3. The LES tariffs includes a discount network level at LV substation. This is not a network tier which is currently recognised within the PCDM and no discount percentages are calculated for this voltage tier. This may create distortions or perverse incentives for networks to be operated on a licence exempt basis where a greater discount is available to a LES than would be available to an LDNO for the same connection. 4. DNOs only bill IDNOs use of system for conveying electricity to and from the DNO/IDNO boundary. IDNOs are responsible for billing suppliers a bundled use of system charge (a charge for the DNO system and a charge for the IDNO system); i.e. the IDNO is responsible for billing the supplier and collecting the upstream DUoS revenues on behalf of the DNO. To offer such service to private network operators, may be discriminatory – and potentially an abuse. We do not see why private network operators should be unduly advantaged over IDNOs in respect of this.	

UK Power Networks	Non-confidential	Solution A (Rebates) would as stated earlier, add significant complexity to the arrangements and in our view should not be progressed further. IDNOs face a lot of the costs which PNOs do not, such as MPRS and DUoS systems and the associated costs, any change brought forward which puts in place arrangements for Private Networks needs to make sure this is fully considered, to ensure that IDNO business models are not negatively impacted.	
Western Power Distribution	Non-confidential	There may be cases where the private network charge is less than the IDNO discount for a particular private network? If this is the case then a DNO connected to an IDNO connected to a private network could result in an IDNO who mirror the DNOs tariffs having to pay the PNO overall.	

Company	**Confidential / Anonymous**	**13. (Mandatory for DNO Party's only, optional for other DCUSA Parties): Are there any unintended consequences associated with DCP328 and licence obligations?**	
Emergent Energy Systems Ltd.	Non-confidential	n/a	
Electricity North West	Non-confidential	Rebates to be paid to non-DCUSA Parties could require licence changes. Such as changes to enable the payment of rebates to PNOs, and the changes required to ensure the cost of rebates are recovered through Allowed Revenue.	
ESP Electricity Limited	Non-confidential	We would note that on the argument listed in paragraph 4.89, should an obligation be placed in code that contradicts the license, we would expect the license take precedence and render the code obligation invalid rather than both obligations being valid. As a matter of principle, we agree with the Proposer that the Authority must provide a view on this prior to parties are allowed to make a vote on this CP.	
Northern Powergrid	Non-confidential	Yes. As set out in the consultation, whilst we remain concerned about the perceived issue that DCP328 seeks to address (fairness in ensuring the revenue recovered from the private network as a whole is equivalent if competition in supply exists behind the private network or not), we are mindful that DNOs have a licence requirement to have in force a use of system charging methodology(ies), and where the respective conditions	

		(SLC13A and SLC13B – see Designated Properties and Designated EHV Properties respectively) apply to "premises" or "Distribution Systems" that are "connected to the licensee's Distribution System" (i.e. customers connected to the distribution network, and therefore not customers connected to private networks). Our licence does not specifically contemplate us calculating charges for customers who do not satisfy these definitions, and whilst we recognise that DCP328 seeks to extend the application of the relevant DCUSA Schedules (16 to 18) beyond these licence definitions (i.e. to customers not directly connected to our network), it is beyond the remit of our licence and therefore we do not believe that DCP328 can better facilitate the Relevant Objectives within it (for reference, these are consistent with the DCUSA Charging Objectives). Therefore, there will be an explicit contradiction between the DCUSA and distribution licence that the Authority must consider when deciding on DCP328.	
Power Data Associates Ltd	Non-confidential	n/a	
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	None that we are aware of or have identified in this Consultation documentation	
ScottishPower Energy Retail Ltd	Non-confidential	-	
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	None.	
SSE Generation	Non-confidential	We note the proposer's concern that the proposed DCUSA changes are not currently underpinned by the distributors' licence obligations and may create a conflict. This is because the proposed solutions involve creating new tariffs which relate to customers behind the PNO boundary, whereas, under their SLCs 13A and 13B (relating to the CDCM	

		and the EDCM), distributors' obligations extend to 'Designated Properties' only, which appears to not include customers behind the PNO boundary. We believe that this concern is addressed by EU regulations (Article 37 of the 2009/72 Third Energy Package, para 6., as adopted into UK law through the Brexit Withdrawal Act), which states that the regulatory authority shall be responsible for fixing or approving transmission and distribution tariffs or their methodologies. In the legal hierarchy, the EU regulation sits above the licence and therefore supersedes it, which, in our view, gives the regulator the powers to approve the proposed charging methodology changes even though they are not underpinned by the distributors' licence.	
The Electricity Network Company Limited	Non-confidential	We do not believe it is within the vires of DCUSA to mandate a licensed distributor to charge, bill and collect use of system revenues in respect of consumers that are connected to the distribution system of a third party (operating under a licence or licence exemption). We do not think that it is within the vires of DCUSA to extend the duties placed on distributors beyond those set out in the Electricity Act 1989 or in the relevant distribution licence. Given our concerns in other areas we believe that there is still significant work to be done on the development of this change proposal. As such we would welcome some further clarity from Ofgem ahead of the change declaration phase of the change proposal so any additional effort to develop the change is not wasted.	
UK Power Networks	Non-confidential	We have nothing further to add to the view of the proposer, which is noted in the consultation document. We would welcome a view from the Authority before this change is taken further forward and voted upon by parties.	
Western Power Distribution	Non-confidential	If the rebate mechanism is adopted and this is going to be recovered through a pass through mechanism then a licence change would be required.	

Company	**Confidential / Anonymous**	**14. Do you have any comments on the legal text?**	

Emergent Energy Systems Ltd.	Non-confidential	n/a	
Electricity North West	Non-confidential	We note there is a difference between the drafting of para 29.5A for Solution A and B as shown below, we suggest the Solution A text should read “or” rather than “and”. Solution A 29.5A The following provisions shall apply in the case of an Entry Point or Exit Point on the Company’s Distribution System that is subject to a Difference Metering arrangement and a Shared Metering arrangement: Solution B 29.5A Where an Entry Point or Exit Point on the Company’s Distribution System is subject to a Difference Metering arrangement or a Shared Metering arrangement	
ESP Electricity Limited	Non-confidential	No comments.	
Northern Powergrid	Non-confidential	We feel that the legal text reflects the solutions as they have been proposed.	
Power Data Associates Ltd	Non-confidential	no	
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	No	
ScottishPower Energy Retail Ltd	Non-confidential	No	
SP Energy Networks (SP	Non-confidential	None	

Distribution & SP Manweb)			
SSE Generation	Non-confidential	*Legal text for option B* p.7, schedule 16, at the top of para 88 – the text still refers to both fully settled and shared metering. We believe the latter reference (to shared metering) should be deleted, as the solution set out at para 88 should only apply to fully settled metering. p.26, schedule 18, para 28.5 – ditto? We suggest all other legal text is also checked on this point.	
The Electricity Network Company Limited	Non-confidential	We have no specific comments on the legal text beyond the broader concerns we have outlined with respect to the solution and approach taken.	
UK Power Networks	Non-confidential	Depending upon the solution chosen, we have identified a few areas where the legal text would require additional work including where the DCs are involved, and on the rebate solution over how that would be treated where a negative value is to be recovered.	
Western Power Distribution	Non-confidential	The following statements in the legal text state that the capacity elements and reactive power elements will be allocated to the fixed charge based using an average kVA or kVArh. Why have the charging methodologies been altered in this way? Capacity charge elements (p/kVA/day) for half-hourly site-specific settled customers connected to Licence Exempt Systems are allocated to the fixed charge (in p/day) by multiplying the capacity charge by the average kVA per customer for an equivalent customer, determined from the DNO Party's volume forecast for the equivalent half-hourly metered tariff at that voltage. Reactive power charge elements (p/kVArh) for half-hourly site-specific settled customers connected to Licence Exempt Systems are allocated to the fixed charge (in p/day) by multiplying the reactive power charge by the average kVArh per customer for an equivalent customer, determined from the DNO Party's volume forecast for the equivalent half-hourly metered tariff at that voltage, and dividing by the number of days in the charging year.	

		As the capacity element is a large part of the charge it does mean that it is possible for a PNO customer with a high usage and small capacity (High load factor) to have to pay more as a private network than as an all the way customer.	

Company	Confidential / Anonymous	15. Do you believe that the DCUSA Charging Objectives are better facilitated by this CP? Please provide your rationale	
Emergent Energy Systems Ltd.	Non-confidential	n/a	
Electricity North West	Non-confidential	We believe that any solutions that apply different charges based on metering arrangements (difference metering, fully settled, etc.) to the same connections on the DNO network are not properly reflecting the costs incurred by the DNO, and so do not better facilitate Charging Objective 3. We share the views of the proposer that objective 6 (…efficiency in … administration) is adversely impacted.	
ESP Electricity Limited	Non-confidential	Having noted our concerns in question 12, we cannot currently support that notion that the charging objectives are positively impacted by this CP and believe that charging objectives 2 and 3 are negatively impacted due to a lack of consideration on the impacts for wider IDNO charging. We would also question whether this change proposal has received inputs from PNO parties to confirm that the impacts on the charging objectives are likely to be materialised.	
Northern Powergrid	Non-confidential	No. Whilst, as the proposer, we remain concerned about the perceived issue that DCP328 seeks to address, we believe that DCUSA Charging Objectives 1, 3 and 4 will be negatively impacted in the absence of licence changes and (as a minimum) consent from the Authority for DNOs that activities carried out can stray from the Distribution System.	
Power Data Associates Ltd	Non-confidential	1 positive - this change ensures that the licensed distributor only retains the costs for managing their part of the distribution network	

		2 positive – this change does not (as far as possible) discriminate between customers connected directly to a DNO network or via a PNO 3 positive – all charges are averaged to a degree, these proposal do the same to seek to balance effort vs. reward. 4 positive – ensure a level playing field in the costs of provision of a DNO and PNO network 5 none 6 positive – creates a framework that is balances the costs of rebate with the administrative effort.	
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	The DCUSA Charging Objectives 2 & 4 are better facilitated by this change.	
ScottishPower Energy Retail Ltd	Non-confidential	Agree with those in CP	
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	Charging Objective two – positive the change will prevent distortion in the application of use of system charges for some or all customers connected to private networks where there is competition in supply. Charging Objective three – positive the charges will be brought into increase alignment for all PNOs despite there metering arrangements and whether they adopt competition in supply or not. Charging Objective four – positive There are increasing volumes to facilitate competition in supply on private networks. Introducing transparency removed any future risk of inconsistent application by DNOs of the common charging methodologies. Charging Objective four – negative	

		Increased complexity is introduced into the revenue recovery process, billing process and common charging methodologies.	
SSE Generation	Non-confidential	*1. Discharge by the DNO Party of their obligations under the Act and the distribution licence* Neutral - although the proposed DCUSA changes appear not to be underpinned by the distribution licence, we consider that relevant EU regulations sufficiently cover this issue (see our response to q.13). *2. Facilitation of competition* Yes, in the case of solution B, as this proposal creates a mechanism which seeks to ensure that PN DUoS charging arrangements do not create a detriment compared to distribution charging arrangements. *3. Cost-reflective charges* Neutral – as the scope of the proposal doesn't cover cost-reflective charges. However, based on the Working Group's impact assessment, we consider that solution B achieves a marginally fairer outcome in terms of the residual charges than solution A. *4. Developments in each DNO Party's business* Yes, as the DNOs are having to address an existing defect, i.e. the current lack of a common approach amongst DNOs around Use of System charging for PNs with competition in supply. *5. Compliance with the Regulation on Cross-Border Exchange and other EC/ACER decisions* Neutral. 6. Efficiency in implementation/administration of the charging methodology Yes. Whilst the proposal creates additional complexity, it also ensures that all DNOs follow the same approach when collecting DUoS charges from PNs and their customers.	
The Electricity Network Company Limited	Non-confidential	No, our views are set out below Objective 1 - None Objective 2 – Negative. As we have illustrated in our response to question 12 we believe that this change proposal prevents and distorts competition in distribution of electricity. We believe that the margins available to IDNO and DNO out of area networks will be	

		impacted to the extent where networks operation under a licence becomes unviable in some circumstances. This restricts competition in licenced distribution and has the distortive effect of unduly incentivising licence exempt network operation. We do not believe that the change proposal has sufficiently demonstrated that there is an issue where competition in supply to customers on private networks which have requested such competition is being distorted by the application of inappropriate UoS charges. Objective 3 – Negative. The change proposal does not consider the cost reflectivity of charges as it is driven entirely by a model which is designed to incentivise behaviour over ensuring cost reflective charging (i.e. 500MW model). Cost reflective charging can only be demonstrated where discounts are calculated based on a total cost model and the total costs (including full operational costs, overheads and oncosts) avoided by the DNO are considered. We have outlined this in full in our responses to questions 4, 8 and 12. Objective 4 – Neutral. The responsibility, under the provisions of the Act to facilitate competition in supply of electricity are placed on the licence exempt distributor. We do not see how this extends upwards to the DNO and we do not believe, therefore, that this change proposal takes into account developments in the DNO Parties' distribution businesses. WE understand that the DNOs may be seeing more applications for the provision of MPAS under licence condition 35 but we do not believe that this change proposal which is seeking to calculate a tariff/rebate for fully settled sites is required to take that into account. Objective 5 – None Objective 6 – Negative. Again, we agree with the working group's assessment that this will have a negative impact. We think that it is possible that dependent on the solution, the quantum of this issue is understated by the working group's assessment. If the solution requires billing system and/or great swathes of data to be created we think this has the potential to have a significant impact for the charging methodology to be efficiently implemented and administered.	
UK Power Networks	Non-confidential	We believe that Charging Objectives two and three are likely to be better facilitated by this change by not distorting charges levied to Private Networks. Charging Objective four is also better facilitated as if progressed this change would bring forward clarity from a regulatory perspective. However charging objective six is negatively impacted by this change by introducing additional complexity in the charging arrangements, although we appreciate this would be necessary to ensure cost-reflectivity is maintained.	

Western Power Distribution	Non-confidential	WPD agree with the group that in most cases the DCUSA charging objectives 2, 3, and 4 are better met and 6 is negatively impacted. However, as there are some customers that will have a higher charge for the LES tariff than the ATW tariff and as it is possible that the LES tariff at a particular voltage level is less than the IDNO tariff at the same voltage the satisfying of the DCUSA objectives are not universal for all customers.	

Company	**Confidential / Anonymous**	**16. If this change was approved, when should it be implemented? Please provide your rationale if different to April 2022**	
Emergent Energy Systems Ltd.	Non-confidential	n/a	
Electricity North West	Non-confidential	The implementation date seems ambitious considering the scope of this change (changes to billing system, licence etc.) and potential interactions with the Ofgem Access SCR.	
ESP Electricity Limited	Non-confidential	There should be a minimum lead time of six months between authority approval and change implementation to allow parties to develop, test and implement any required system changes necessary.	
Northern Powergrid	Non-confidential	Setting aside our fundamental concerns as to the impact on the DCUSA Charging Objectives/Relevant Objectives (in the distribution licence), we believe that DCP328 should be implemented in April 2022 (meaning a direction from the Authority would be required in line with DCUSA Section 2A Clause 19.1B, that the notice periods set out in Clause 19.1A of that same schedule need not apply).	
Power Data Associates Ltd	Non-confidential	April 2022 is reasonable. The approach of any reclaimed charges in 2022/23 year would be recovered by Distributors in future years, so there is no loss of allowed revenue.	
Scottish Hydro Electric Power Distribution plc and Southern	Non-confidential	1 April 2022 will require re-publication of charges, subject to less than 15 months' notice and availability of necessary models and will require Direction from the Authority. Otherwise, it would have to be 1 April 2023.	

Electric Power Distribution plc			
ScottishPower Energy Retail Ltd	Non-confidential	Assume April 2022 has been selected as there should be no impact on the finalised charging statements already issued by all DNOs / IDNOs. If there is an impact our preference would be April 2023 as suppliers are already pricing contracts based on the current published charges.	
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	The CP timetable indicates that an Authority decision of October 2021. Some of the proposed options would require significant changes to DURABILL which we believe would be impractical to implement in time for an April 2022 go-live. The options that we would have particular concerns with are those where DURABILL would be used to: i) Determine the boundary meter data for shared systems or difference metering ii) Calculate PNO rebates.	
SSE Generation	Non-confidential	Under the standard notice period for UoS charges, the originally envisaged implementation date of April 2022 would not be possible. Implementation in April 2023 would be possible, provided Ofgem has made a decision by the end of September 2021.	
The Electricity Network Company Limited	Non-confidential	We believe that a full assessment of the solution and the impacts to distribution businesses to be able to bill/assign rebates is required to be able to confirm the implementation date but we think that it is highly unlikely that April 2022 will be a suitable date for implementation of this change proposal.	
UK Power Networks	Non-confidential	The charges have already been set for April 2022, and although the changes brought about by DCP328 are not expecteded to be material to the ATW charges, we believe that allowing sufficient time to ensure all appropriate processes and arrangements are in place, would result in April 2023 being a more appropriate implementation date.	
Western Power Distribution	Non-confidential	April 2022 prices and forecast units are set already. If this was implemented for April 2022 then DNOs revenue will be negatively impacted. This should be implemented for April 2023 or 2024.	

Company	Confidential / Anonymous	17. Any other comments?	
Emergent Energy Systems Ltd.	Non-confidential	n/a	
Electricity North West	Non-confidential	It is our view that aggregate DUoS charges should be identical under all potential scenarios for the same connection and load on the DNO network, including scenarios such as: no competition in supply, the various metering arrangements discussed in the consultation document, or a single site/customer. We do not believe this would be achieved by the tariff solution for fully settled metering installations. As part of the role of the private network owner, and to enable competition, we suggest PNOs could be asked to identify which customers are on their networks and industry processes could then be put in to place to create pseudo boundary meter data that could be used to bill an appointed supplier DUoS. The benefit of this solution is that it ensures that the DUoS charges to the DNO are the same under all metering arrangements.	
ESP Electricity Limited	Non-confidential	None.	
Northern Powergrid	Non-confidential	None at this time.	
Power Data Associates Ltd	Non-confidential	It has been a long process. It would be good to get these proposals over the line. As part of other industry changes it would be good to capture the distinction between a directly connected DNO MPAN and an indirectly connected PNO customer. These records can be populated as information becomes available, new connections and from PNO rebate claims.	
Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution plc	Non-confidential	No	

ScottishPower Energy Retail Ltd	Non-confidential	-	
SP Energy Networks (SP Distribution & SP Manweb)	Non-confidential	None	
SSE Generation	Non-confidential	a) We expect that elements of the solution may result in the disclosure of data not currently in the public domain. We would like greater clarity on this, as well as the opportunity to comment, to avoid that commercially sensitive information pertaining to specific private networks is published which could adversely affect competition. b) We note that with regard to a competition law concern raised in response to the first consultation, the Working Group concluded that for a DNO to be certain that it is compliant, it would need to undertake an AEC test, and do so of its own accord, since it cannot be compelled to do so. The outcome of this test may help a DNO form its position on the proposals. We don't feel that the competition concern has been sufficiently well articulated, and we therefore find it difficult to comment. However, we would have serious concern if the approval of this change proposal created an increased risk of breached of competition law compared to the status quo. We are looking to Ofgem to determine whether this is the case.	
The Electricity Network Company Limited	Non-confidential	We believe that the assessment of this change would be more readily completed if a broader access to some final tariffs were available. We have attempted to undertake some work to highlight our concerns but we are aware that this work is incomplete and does not consider the broad range of eventualities for private network operation. We would welcome further transparency of the tariffs, if possible, ahead of the voting phase for this change proposal We are also concerned that the development of this change is hindered by the lack of an AEC test being undertaken. We note and accept the working group's comments in the consultation that no party can compel the DNO to undertake the AEC test but parties considering their votes on this change proposal are doing so with incomplete information about the consequences of the change. Any further work which can be done to alleviate these concerns will aid the development of this change proposal and provide industry	

		parties with the comfort that they need to be able to vote in favour of this change proposal. We disagree with the assertion in paragraph 3.2 of the consultation that "…*the Distributor is obliged to provide Meter Point Administration Services to customers on the private network*". SLC 17.1 only places an obligation on licensed distributors to offer MPAS in respect of premises connected to its distribution system. SLC 17 places no obligation on distributors to offer MPAS on third party networks. Although SLC35 sets out an obligation to provide MPAS and Data transfer Services, the duty only applies to DNOs operating within their distribution services area. It does not apply to IDNOs or DNO networks which are outside their distribution services area. Either way, the provision of such services is subject to agreement – such agreement would be between the private network operator and the relevant DNO. Therefore, whilst a DNO may obliged to offer MPAS services to a private network connected to an IDNO network, the IDNO is not.	
UK Power Networks	Non-confidential	Although the numbers of PNOs are small currently, should sufficient arrangements be implemented then this is likely to increase and currently there is no system in place to fully manage the arrangements. This would also likely see significant costs faced by Suppliers as well as all LDNOs, as a result consideration and a full impact assessment on these parties would need to be considered.	
Western Power Distribution	Non-confidential	OFGEM as an independent body from DNO's, IDNO's and PNO's will need to apply competition tests.	