DCUSA

DCUSA Consultation	At what stage is this document in the process?
# DCP 328 ## Use of system charging for private networks with competition in supply *Raised on 15th August 2018 as a Standard Change*	01 – Change Proposal **02 – Consultation** 03 – Change Report 04 – Change Declaration

Purpose of Change Proposal:

The intent of this change is to ensure that use of system charging remains cost-reflective when competition in supply on a private network is in place.

	The Workgroup recommends that this Change Proposal should proceed to Consultation. Parties are invited to consider the questions set in section 9 and submit comments using the form attached as Attachment 3 to dcusa@electralink.co.uk by **02 July 2021.** DCP 328 has been designated as a Part 1 Matter and a standard change. The Working Group will consider the consultation responses and determine the appropriate next steps for the progression of the Change Proposal (CP).
	Impacted Parties: DCUSA parties: Suppliers, DNOs and IDNOs Others: private network operators and customers connected to private networks.
	Impacted Clauses: Clause 1 – definitions Clause 29 – metering equipment and metering data Schedule16 - Common Distribution Charging Methodology Schedule 17 - EHV Charging Methodology (FCP Model) Schedule18 - EHV Charging Methodology (LRIC Model); and Schedule 20 – Production of Annual Review Pack

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Timetable

The timetable for the progression of the CP is as follows:

Change Proposal timetable

Activity	Date
Initial Assessment Report Approved by Panel	08 August 2018
First Consultation issued to Parties	01 February 2019
Second Consultation Issued to Parties	04 June 2021
Change Report issued to Panel	11 August 2021
Change Report issued for Voting	20 August 2021
Party Voting Ends	10 September 2021
Change Declaration Issued to Parties	14 September 2021
Authority Decision	19 October 2021
Implementation	01 April 2022

Any questions?

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1 Summary

What?

1.1. There are several scenarios in which multiple customers can be connected to an electricity distribution system (private network) operated by a licence exempt distributor (known throughout this document as a Private Network Operator (PNO)) with that private network then connected to the local Distributor's[1] network further upstream.

1.2. Where such private networks exist, there is only one connection to the Distributor's network at the point where the private network connects to the wider network. The private network then serves multiple customers, generally operating under an exemption from holding a Distribution licence. In some circumstances, the PNO will appoint an electricity Supplier, and will pay a single electricity bill in respect of a single Meter Point Administration Number (MPAN) at the ownership boundary between the Distributor and the PNO, which is then shared amongst the customers connected to the private network through some agreed contractual framework (potentially using some private metering on each customer's connection to the private network to determine that customer's share of the total bill).

1.3. The Electricity and Gas (Internal Markets) Regulations 2011[2] introduced new obligations on PNOs and supply undertakings, including a duty to facilitate third party access to their electricity and gas networks. Customers connected to a private network are entitled to request competition in supply. PNOs are obliged to deliver this if requested although there are some exceptions which are detailed in those regulations. This means that, rather than the customer paying their share of the total electricity bill for the entire private network, the customer can enter into contract with their chosen Supplier to provide their electricity and pay a separate electricity bill to that Supplier. The DNO Use of System (UoS) charges were explored during an earlier change to DCUSA, DCP158 – "DNO DUoS re EDNOs" which was rejected by the Authority. Documentation detailing the timeline of regulatory events and the obligations on parties, which formed part of that CP, is in Attachment 4.

1.4. In order to facilitate competition in supply, Distributors are required to provide additional MPANs to be used for customers who have requested competition in supply in order to differentiate units which relate to that customer from the remainder of the customers connected to the private network. This creates complications for UoS charging. For half hourly site-specific settled customers (i.e. those in measurement class C, D or E), Distributors receive usage data by MPAN in order to invoice UoS charges, with an invoice being issued per MPAN per month. Hence when competition in supply is in

[1] A licensed distributor is either a Distribution Network Operator or an Independent Distribution Network Operator, collectively known in this consultation document as Distributors unless the text is specific to either party.

[2] http://www.legislation.gov.uk/uksi/2011/2704/pdfs/uksi_20112704_en.pdf

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place, if the Distributor followed standard processes, it would issue an invoice in respect of each MPAN, some of which in fact relate to customers connected to the private network.

1.5. The Distributor only has a relationship with the PNO (as the party which has a connection to the Distributor's network), with that relationship likely to be underpinned by a connection agreement, detailing the maximum import (and if applicable maximum export) capacities of the private network.

Why?

1.6. Without clarity in the charging methodology, there is a risk that Distributors will take different approaches, undermining the intended commonality of the charging methodologies.

1.7. Competition in supply on a private network does not alter the use of the Distributor's network; hence the CP form asserts that the UoS charges faced by the multiple Suppliers involved when competition in supply is in place should sum to the same total as would be applied if a single Supplier were supplying the site as a whole.

1.8. When competition in supply is not in place (i.e. there is a single Supplier and one MPAN) fixed and capacity charges would be applied in respect of that single MPAN. Where competition in supply is in place (i.e. there are multiple Suppliers and multiple MPANs), if all tariff elements are applied in respect of all MPANs (as would be expected), multiple fixed and capacity charges would be applied. This undermines the equivalence in charges (which the CP suggests should be seen) faced by the single Supplier (where competition in supply is not in place) and the sum of charges faced by multiple Suppliers (where competition in supply is in place).

How?

1.9. Within the first consultation there were a number of possible solutions to this issue proposed. After consideration of feedback received and further analysis by the Working Group, two solutions have been further defined based on the type of metering arrangement[3] that exists on the PNO network. The only difference between the two is how to charge in the CDCM for fully settled metering installations, by either providing a rebate to the PNO or charging the embedded supplier based on new tariff arrangements.

Solution A

For difference metering and shared metering installations in both the Common Distribution Charging Model (CDCM) and the Extra High Voltage (EHV) Distribution Charging Methodology (EDCM), the Distributor should charge the boundary supplier only.

For fully settled metering installations:

- provide a rebate to PNOs in the CDCM; and

[3] This is explained further in section 3.

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- charge the embedded suppliers in the EDCM.

Solution B

For difference metering and shared metering installations in both the CDCM and the EDCM charge the boundary supplier.

For fully settled metering installations:

- charge the embedded suppliers in the CDCM; and
- charge the embedded suppliers in the EDCM.

1.10. The proposed solution for difference metering suggested by DCP158[4] was for the boundary supplier to provide gross boundary data. This is also being proposed within this change proposal with an alternative approach being for the Distributor to calculate the gross data based on the settlement data received from the boundary settlement meter and the embedded settlement meters.

1.11. The solution also considers how the residual charges are to be applied to Metering Points within the private network. This was deferred from the Targeted Charging Review (TCR) change proposal DCP361[5].

1.12. The Working Group agreed that there is no reason to change the definitions of Single Site or Final Demand Site (as introduced by DCP359 for the purposes of residual charges following the TCR) for complex sites within a private network.

2 Governance

Justification for Part 1 Matter

2.1. The Proposer considers that this CP should be considered a Part 1 Matter as it satisfies one or more of the following criteria:

a) it is likely to have a significant impact on the interests of electricity consumers;

b) it is likely to have a significant impact on competition in one or more of:

i. the generation of electricity;

ii. the distribution of electricity;

iii. the supply of electricity; and

iv. any commercial activities connected with the generation, distribution or supply of electricity.

[4] DNO DUoS re EDNOs
[5] Ofgem Targeted Charging Review Implementation: Calculation of Charges

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Current Next Steps

2.2. This Consultation Document is issued for a period of four weeks. The Working Group will review the responses after this period and decide whether to move to the change report stage.

3 Why Change?

Background of DCP 328

3.1. Elexon have a guidance document for Third Party Access to Licence Exempt Distribution Networks[6]. This focuses on the Balancing and Settlement Code (BSC) obligations and processes associated with facilitating competition in supply (referred to as 'third party access') for electricity customers connected to private networks. The proposed options detailed in this consultation are designed to work with the options available for settlement where competition in supply is in place, as summarised in that guidance, namely:

- difference metering;
- full Settlement metering; or
- shared metering.

3.2. Under all metering options, the Distributor is obliged to provide Meter Point Administration Services to customers on the private network and in so doing provides MPANs against which metering data is recorded in Settlement, including the MPANs where data is received from the non-settlement meters associated with the shared metering arrangements.

Difference Metering

3.3. In order for difference metering to be used to facilitate competition in supply for customer 1, metering arrangements as shown in figure 1 would be required.

[6] Third Party Access to Licence Exempt Distribution Networks

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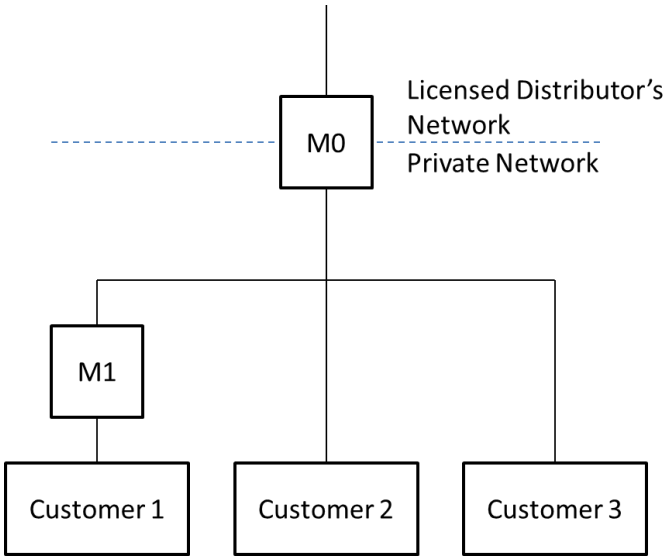

Figure 1 - competition in supply using difference metering

3.4. In order for difference metering to be used, all metering systems involved ('M0' and 'M1' in this example) must be half hourly metering systems.

Full Settlement Metering

3.5. In order for full Settlement metering to be used to facilitate competition in supply all the customers on the private network must have settlement metering and there is no settlement boundary meter as shown in figure 2 below.

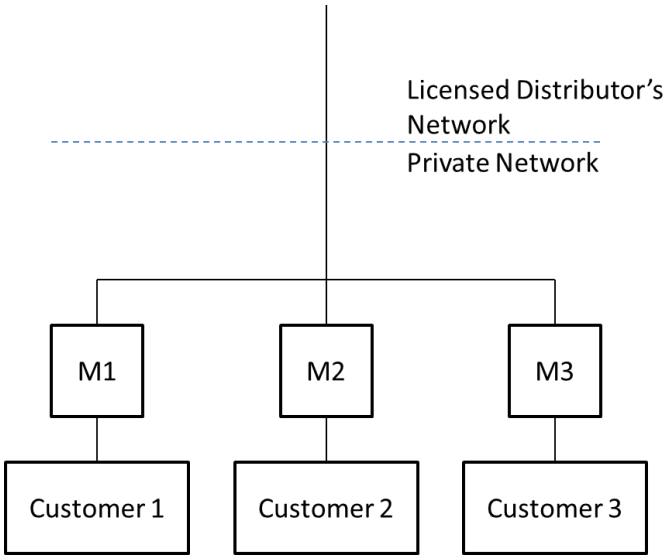

Figure 2 - competition in supply using full Settlement metering

3.6. The BSC refers to such an arrangement as an 'Associated Distribution System' and requires all the entry and exit points to be metered. Full Settlement metering can be used with either half hourly metering systems, non-half hourly metering systems, or a combination of the two, and is often used for connections such as blocks of flats, where the ownership boundary between the Distributor and the PNO is at the base of the building whilst each flat is separately metered – the rising mains within the building form a private network or 'Associated Distribution System'.

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3.7. Under a full Settlement metering approach, Settlements metering that measures the usage of customer 1, customer 2 and customer 3 would be used in Settlement under separate MPANs, with the boundary meter (previously 'M0') no longer used.

Shared Metering

3.8. In order for shared metering to be used to facilitate competition in supply for customer 1, metering arrangements as shown in figure 3 would be required.

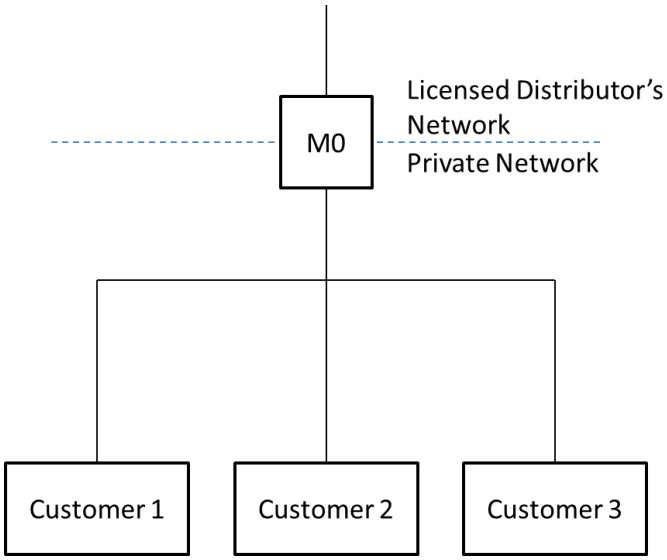

Figure 3 - competition in supply using shared metering

3.9. In order for shared metering to be used, all metering systems involved must be half hourly metering systems.

3.10. Under a shared metering approach, Settlements metering at the boundary (i.e. measuring the usage of all **three** customers) is used to determine the total units entered into Settlement, with non-Settlement metering measuring the usage of each individual customer being used to determine the proportion of the total units in Settlement which is allocated to each Supplier. The means of allocation is agreed between the Suppliers in question, with the most straightforward mechanism being simply proportional to the units used by each customer.

Use of System Charging Implications

3.11. Under all metering options, the ownership boundary between the Distributor and the PNO remains unaltered, and the connection agreement is between the PNO and the Distributor, with the agreed capacity reflecting the agreed capacity at the boundary. Assuming each of the customers does not alter their usage in this process, this will remain appropriate, as units through the boundary will not change. Given the boundary arrangements have not changed, and usage of the Distributor's network has also not changed, the Proposer of this CP asserts that total UoS charges should not change because of competition in supply in a private network.

3.12. However, under each of the three metering options, there will be multiple MPANs with metering data in Settlement. Under current processes, the Distributor would assign a tariff to each MPAN reflecting

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the type of customer connected and the voltage of connection, and then invoice the registered Supplier of each MPAN accordingly based on data received through Settlement.

3.13. The CP form (Attachment 5) highlighted a number of issues for UoS charging and associated administration as below:

a) **Assigning tariffs:** Depending on the tariffs which the Distributor assigns to each customer, there is a risk that the Distributor will be invoicing in respect of assets which are in fact private network assets.

b) **Losses within the private network:** Losses within the private network may not be accounted for in the units in Settlement. This issue is currently resolved by the BSC Guidance Note 'Third Party Access to Licence Exempt Distribution Networks' for all metering options.

c) **Fixed charges:** Where competition in supply is not in place, one fixed charge will be applied in respect of the one MPAN at the boundary. Where competition in supply is in place, fixed charges will be applied in respect of all MPANs.

d) **Agreed capacity charges:** Where competition in supply is not in place, one agreed capacity charge will be levied at the boundary, based on the capacity agreed between the Distributor and the PNO, formalised in a connection agreement. It is not clear what agreed capacity the Distributor should charge in respect of MPANs which relate to connections to the private network where the Distributor has no commercial relationship with the customer and so no basis on which to determine the agreed capacity.

e) **Excess capacity charges:** Where competition in supply is not in place, one excess capacity charge will be levied at the boundary if the aggregate usage of all customers connected to the private network (as measured by the boundary metering) exceeds the agreed capacity at the boundary; if not, no excess capacity charge will be levied. Simply allocating boundary capacity between end users on the private network may result in excess capacity charges being applied where none would be applied in the scenario where competition in supply is not in place.

f) **Charging for export sites:** If one of the sites within the private network includes some generation which exports onto the private network, the units exported are likely to be used by other customers within the private network, and so will offset flows at the ownership boundary between the Distributor and the PNO. The import and export units for each customer within the private network will be seen separately in Settlement, and so the Distributor will charge import units and (where applicable) credit export units. Generation credits at a given voltage are not the inverse of demand charges at that voltage, and so the total UoS charge for customers connected to the private network will be different if the import and export from each customer is charged separately to that which would have been charged had all usage been charged at the boundary. This issue is currently resolved by using the BSC complex site mapping exercise (BSCP 514).

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g) **Charging for reactive power:** Under the difference metering approach, reactive units metered at customer connections will be deducted from reactive units metered at the boundary. Such differencing will not accurately reflect reactive power flows at the boundary.

h) **Sites with multiple feeders**: there are complications for the difference metering arrangements where a private network has multiple feeders, each with a Connection Agreement, agreed capacity, and possible different voltages. Under this scenario it may not be clear to which of the multiple feeders the differencing should be applied. This issue is currently resolved by using the BSC complex site mapping exercise (BSCP 514).

i) **Residual charges**: an additional issue not considered in the original CP has arisen following the implementation of the TCR solution relating to residual charges. As for the fixed charge element, without competition in supply a single residual charge is applicable based on the boundary connection, however with competition in supply each MPAN will incur a residual charge inclusive within the fixed charge. The allocation of MPANs with competition in supply to residual charging bands and therefore the amount of residual that should be charged to these MPANs is an additional issue to those above.

A response to each of these issues based on each scenario considered within this consultation can be found in Attachment 10.

3.14. DCP 328 is seeking to formalise the approach which Distributors should take when invoicing UoS charges in respect of private networks where competition in supply is in place, to ensure commonality between different Distributors and to maintain cost-reflectivity wherever possible.

4 Working Group Assessment

DCP 328 Working Group Assessment

4.1 A Working Group was established to discuss a number of potential solutions of which more than one option may be chosen based on the complexity of the private network.

DCP 328 first consultation

4.2 To aid the further development of the solution for this CP, the Working Group issued a consultation to parties on 1 February 2019. The aim of the first consultation was to ask the industry for views on the principles of the change and the solution proposed. There were fifteen respondents to the first consultation comprising of eight Distributors, two suppliers, four PNOs and one consultancy organisation. A copy of the first consultation and the Working Group response to comments received can be found in Attachments 1 and 2.

4.3 All respondents indicated that they understood the intent of the CP.

4.4 The Working Group were keen to seek views on whether an appropriate range of PNOs had been considered. The respondents agreed that an appropriate range of PNOs had been identified by the Working Group, whilst there was acknowledgement that it was not an exhaustive list. Some additional examples were raised, for example other large industrial sites, such as chemical works or steel works

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with substantial networks 'inside the fence' and other users such as contractor compounds or tenanted industrial activity.

4.5 The majority of the respondents were supportive of the principles of the CP. One respondent stated that there was no evidence that competition law requirements had been considered when reviewing the solutions. The Working Group have considered competition law requirements for the proposed solutions detailed later in this document.

4.6 The solutions which the Working Group put forward in the first consultation were as below:

- Option 1 – Invoice only the boundary Supplier;
- Option 2 – Invoice all Suppliers based on the tariff which the Distributor would apply if the end user were connected at the ownership boundary between the Distributor and the PNO with a correction to fixed charges and some form of capacity allocation;
- Option 3 – Invoice all Suppliers as if the customer were connected to the Distribution network, with the PNO able to 'claim' some UoS revenue back from the Distributor in respect of private network assets;
- Option 4 – Invoice the PNO direct; and
- Option 5 – Invoice all Suppliers based on new UoS charges which only include elements of charging which relate to voltage levels provided by the Distributor.

Option 1 – Invoice only the boundary Supplier.

4.7 Under this approach, the Distributor would continue to invoice UoS charges only to the Supplier registered to the boundary MPAN in Settlement. In order to invoice all units, this solution requires the Distributor to either receive or be in a position to calculate gross units at the boundary, whereas Settlements will only show net units (i.e. with units used by embedded customers having been differenced from the boundary MPAN).

4.8 The PNOs that responded to the first consultation were supportive of this option, whilst recognising that the solution is not appropriate for all types of PNOs and that it is likely that more than one solution will be required to cater for all PNO types. One respondent raised concerns regarding the collection of data and how practical this would be.

4.9 The Working Group concluded that this option should be progressed further but could only be part of a solution since it only caters for difference metering.

Option 2 – Invoice all Suppliers based on the tariff which the Distributor would apply if the end user were connected at the ownership boundary between the Distributor and the PNO with a correction to fixed charges and some form of capacity allocation.

4.10 Under this approach, the Distributor would invoice based on units received through Settlement, using the tariff which the Distributor would apply if the customers were connected at the ownership boundary between the Distributor and the PNO UoS charges to:

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- both the boundary Supplier and the Supplier of embedded customers (under the difference metering approach); or
- the Suppliers of all embedded customers (under the full Settlement or shared metering approach).

4.11 Most of the respondents were not supportive of this option. Concerns were raised regarding the process of allocating fixed and capacity charges to customers. The Working Group concluded that it would not consider this option further.

Option 3 – Invoice all Suppliers as if the customer were connected to the Distributor's network, with the private network operator able to 'claim' some use of system revenue back from the Distributor in respect of private network assets.

4.12 Under this approach, the Distributor would invoice both the Supplier of the embedded customers and the boundary Supplier UoS charges as if those end customers were connected direct to its network. As a result, the Distributor would have recovered some UoS charges in respect of assets on the private network, to which the PNO should be entitled, and so the PNO would be eligible to claim back a portion of UoS revenue from the Distributor.

4.13 There was support for this option from parties although concerns were raised over how the claim would be administered since this would be outside of DCUSA. It was also suggested that this may be a simple solution where fully settled and shared metering arrangements exist. The Working Group agreed to consider this option further.

Option 4 – Invoice the PNO direct.

4.14 Under this approach, the Distributor would invoice UoS charges direct to the PNO based on total units at the boundary, with no charges applied to the units recorded in Settlement against MPANs which relate to customers connected to the private network, or against the boundary MPAN if applicable. The PNO may then directly pass through the Distributor's charges to customers connected to the private network, or recover those costs through another means (e.g. an appropriate commercial agreement).

4.15 Respondents were not supportive of this solution and the Working Group concluded that based on the feedback and their initial assessment of this option it would not be progressed further.

Option 5 – Invoice all Suppliers based on new UoS charges which only include elements of charging which relate to voltage levels provided by the Distributor.

4.16 Under this approach, the Distributor would invoice UoS charges to both the boundary Supplier and the Supplier of embedded customers (under the difference metering approach) or the Suppliers of all embedded customers (under the full Settlement or shared metering approach), based on units received through Settlement, using new tariffs calculated for each Distribution network to private network boundary voltage based on the voltage levels which the Distributor provides. This could be carried out using the calculations in the CDCM which are calculated on a voltage level basis prior to being aggregated to tariff level.

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4.17 Most of the respondents were not supportive of this option. Concerns were raised regarding the process of allocating fixed and capacity charges to customers.

Alternative Option

4.18 The issues raised in response to the first consultation repeatedly highlight the issue of inaccurate fixed, capacity and reactive power charging if existing tariff structures are applied to multiple private network connectees.

4.19 One respondent put forward a potential alternative option relating to a new tariff structure. An example which they considered was whether all PNO customers, whether boundary or embedded, have a fixed charge and unit charges only or unit charges only, with some smearing of capacity/fixed as appropriate. There full response is detailed below:

"The working group appears to have focussed on assigning existing tariffs to this matter. Maybe a new tariff structure needs to be considered. An example which we have considered was whether all PNO customers, whether boundary or embedded, have a fixed charge and unit charges only or unit charges only, with some smearing of capacity/fixed as appropriate. This would largely address the issues of allocating the capacity and other specific elements of the change(s), the DNO would still invoice the Supplier rather than the PNO, which would remove the need to introduce new parties into the DCUSA arrangements. Such an averaging approach could be extended to being unconcerned about the voltage of the boundary connection, which would further simplify the arrangements but would impact cost reflectivity. Although charges within the CDCM and certainly for customers within PNOs already contain an element of averaging. This approach would be practical and largely address the majority of the risks and issues which some of the other options put forward would introduce".

4.20 After Working Group analysis, it was agreed to progress with two solutions. For all sites using the difference metering arrangements option 1 in the first consultation would be used and for all sites using full settlement or shared metering arrangements either option 3 or option 5 would be used in conjunction with the alternative option of only having fixed and unit charges (i.e. capacity and reactive charges forming part of the fixed charge). These options are fully detailed later in this consultation.

DCUSA Objectives

4.21 On the question relating to the DCUSA Charging Objectives and whether they would be better facilitated, a majority of respondents stated that it was difficult to comment at that stage.

Post First Consultation and Targeted Charging Review change proposals

4.22 Post the first consultation and the approval of the TCR Change Proposals (DCPs 359-361 respectively) there have been a number of areas of further development undertaken by the Working Group. These are:

- Shared Metering arrangements;
- Refine the solutions to form part of this consultation including two options on metering data for difference metering and shared metering (i.e. 'complex' sites);
- Complex sites within private networks had been descoped from DCP359;

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- Residual charges for private networks had been descoped from DCP359;
- Competition Act issue raised within the first consultation response; and
- Ofgem clarification on potential licence concerns raised by the Proposer.

Shared Metering Arrangements

4.23 In the first consultation, the approach for private networks with a shared metering arrangement was the same as that of a full Settlement metering arrangement. The BSC caters for primary Suppliers and secondary suppliers and allocates the boundary settlement metered data to each Supplier based on an agreed set of rules contained within BSCP550. Even though the shared metering is based on non-Settlement metering there is an arrangement for allocating between Suppliers the 'unaccounted for' Active Energy (i.e. the difference between the Boundary Point Meter reading and the total of the non-Settlement Meter readings). In addition, all Suppliers in the shared arrangement have MPANS so we assumed a similar approach to sites and to bill each supplier.

4.24 An alternative approach was considered by the Working Group. Under a shared metering arrangement, there is a primary supplier with a primary MPAN and secondary Suppliers who have secondary MPANs. It is the Distributors responsibility to understand how many secondary MPANs relate to a primary MPAN for a site (or in this instant a private network) so this information should be readily available.

4.25 Since there is a boundary Settlement meter, the approach being proposed for difference metering could equally be applied to shared metering, whereby gross boundary metering data is obtained and UoS charges billed to the primary Supplier[7] with both the metering data options still being valid i.e. seek gross data from the data collector or aggregate the primary and secondary MPANs to bill the primary Supplier for UoS. This approach ensures that the agreed capacity at the boundary is charged rather than adding it onto the fixed charge based on similar customer type within the fully settled solution (paragraph 4.47 refers) and is probably more appropriate and accurate. In addition, it also ensures that the total residual charge for the private network with competition in supply is the same as that of a private network without competition in supply.

4.26 The Working Group agreed to progress with shared metering arrangements similar to the difference metering approach i.e. bill the primary supplier based on gross boundary metering data. This approach was then applied to the solutions to be considered during the second consultation with the other areas mentioned above having their own section within the second consultation section.

Q1: 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.

[7] The primary Supplier is responsible for the shared metering arrangements as per the BSC.

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Second consultation

Solutions

4.27 The Working Group agreed to progress with two solutions for consideration during this consultation. The solutions are based on the type of metering arrangement. The first solution considers a combination of three options dependent upon metering type and charging methodology.

Solution A	Difference metering	Fully settled metering	Shared metering
CDCM	Charge the boundary Supplier	Rebate the PNO	Charge the primary Supplier
EDCM	Charge the boundary Supplier	Introduce new tariffs and charge the embedded Supplier	Charge the primary Supplier

Note:

"Charge the boundary Supplier" being option 1 in the first consultation;

"Rebate the PNO" being option 3 in the first consultation with the tariffs to calculate the rebate based on a combination of option 5 and the alternative option suggested in response to the first consultation; and

"Introduce new tariffs and charge the embedded Supplier" based on option 5 in the first consultation.

4.28 The second solution is similar to the first with the only difference being that the rebate to the PNO is changed into a tariff to charge the embedded Supplier where there is a full settled arrangement.

Solution B	Difference metering	Fully settled metering	Shared metering
CDCM	Charge the boundary Supplier	Introduce new tariffs and charge the embedded Supplier	Charge the primary Supplier
EDCM	Charge the boundary Supplier	Introduce new tariffs and charge the embedded Supplier	Charge the primary Supplier

Note:

"Charge the boundary Supplier" being option 1 in the first consultation; and

"Introduce new tariffs and charge the embedded Supplier" being a combination of option 5 and the alternative option suggested in the first consultation for CDCM and option 5 only for the EDCM.

Common to both Solutions

Difference Metering and shared metering (CDCM and EDCM)

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4.29 The proposed solution for difference metering and shared metering arrangements is the same solution proposed for DCP158 "DNO DUoS re EDNOs" which was rejected by the Authority in February 2014. The main reason for rejection was the lack of interaction with PNOs citing:

"We note that the DCUSA working group tried to involve a number of DEHs[8], but that only two DEHs were involved in the consultation process. If approved, the proposal will affect a wide variety of DEHs, including small networks such as caravan sites and housing associations as well large networks such as ports and airports. Due to the limited involvement to date with DEHs, we are concerned about introducing new obligations when those affected may be unaware of the changes and their likely impact"

4.30 Since then, where the difference metering exists this solution has been used and may be considered as standard practice where a boundary meter exists. In addition, the PNOs who responded to the first consultation support its introduction to ensure that a common approach is adopted by the industry.

4.31 The solution for difference metering and shared metering means that all UoS charges are billed to the boundary Supplier or the primary supplier only. No charges will be applied to any Settlement or non-Settlement metering data received for MPANs contained within the PNO network.

4.32 For both difference metering and shared metering a single residual charge would apply at the boundary, with the charging band allocated based on the agreed capacity at the boundary.

Metering Data to support private networks where difference metering and shared metering exists.

4.33 The Working Group considered potential options in calculating gross boundary MPAN data in order to bill the boundary Supplier or the primary Supplier in preference to the existing billing arrangements. The option in the first consultation (specific to difference metering) was to request the boundary Supplier's data collector to provide the aggregated data. An alternative approach was subsequently considered by the Working Group whereby the Distributor could aggregate the Settlement data themselves. Each option is explained in more detail below.

Metering data – Option 1 – gross data received from the boundary Supplier's or Primary Supplier's[9] Data Collector.

4.34 The Distributor will create a non-Settlement MPAN[10] and provide it to the boundary Supplier or the primary Supplier. This non-Settlement MPAN will be used by the boundary Supplier's or primary Supplier's Data Collector to populate the D0036 or D0275 data flow (contained in the Data Transfer Catalogue) with the gross metering data, as if difference metering or shared metering did not exist. An agreement is put in place between Supplier parties so that the boundary Supplier or primary Supplier (or their agent) can aggregate the metering data to comply with a proposed new legal obligation introduced by this change proposal to the DCUSA.

4.35 The existing D0036 or D0275 data flows for the boundary and embedded MPANs (difference metering) or the shared metering MPANs of the primary and secondary Suppliers will not be used

[8] Distribution Exempt Holder

[9] Note that the primary supplier has an obligation to ensure that there is only one data collector to a shared metering system.

[10] the metering data from the boundary MPAN is reduced by the difference metering arrangement, so a new MPAN is being proposed and the metering data associated with it will not enter settlements but by the data collector to provide gross metering data for the distributor to bill UoS charges.

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for billing purposes. This would require a change to the Distributors' billing systems to ensure that this is accommodated and to bill only the boundary Supplier or the primary Supplier based on the data provided on the non-Settlement MPAN.

4.36 The requirement to provide meter time switch codes, suggested in the first consultation, have been removed from the legal text. Consideration is being given within the Market-wide Half-Hourly Settlement Significant Code Review (SCR) as to whether this is required in the BSC, and its use is already governed within a different code to that of DCUSA. Its removal still allows for its use and also ensures that there is no consequential change at a later date.

4.37 The requirement to add a reference within address line 1 of the MPAN address, suggested in the first consultation, is also removed. This may cause a compliance concern with the Master Registration Agreement (MRA) where MAP09 caters for what is required within each address line. The MRA is also subject to an SCR with its closure and movement to the Retail Energy Code (REC). Its removal avoids any further consequential changes due to such a closure.

Metering Data – Option 2 – Distributor calculates the aggregated boundary data.

4.38 The Distributor already receives the metering data from Settlement meters for the boundary Metering Points and the embedded Metering Points in the individual D0036/D0275 data flows for these MPANs and from shared metering arrangements based on BSC obligations. The Distributor will use this data and bill the boundary Supplier for a difference metering arrangement or the primary Supplier of a shared metering arrangement based on the same approach adopted for connections to the distribution network where a site is connected by multiple feeders. This would also necessitate similar clauses allowing the distributor to bill the boundary Supplier or the primary Supplier and aggregate the data of the third party Suppliers with that of the boundary Supplier or the primary Supplier.

4.39 It is recognised that this approach would require changes to distribution billing systems to allow the Distributor to aggregate metering data for different Suppliers and bill the total to the boundary Supplier or primary Supplier, in preference to billing each Supplier on the Settlement or shared metering data received.

4.40 The Working Group would like to understand what the impact of this would be to both systems and business processes associated with each option as part of the response to the option preferred.

Q2: Which metering data option to you prefer? Please provide your rationale, including any cost impacts.

Fully settled arrangements (EDCM)

4.41 It is proposed that there is a two-step approach adopted for each relevant PNO network for EDCM connectees where there is a fully settled arrangement.

4.42 The first step will be to 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. No losses are assumed between the boundary and each embedded customers' premises on the relevant PNO network. The residual charge will be calculated based on the agreed capacity at the boundary.

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4.43 The second step will be the allocation of the 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 for the relevant PNO network. These will be calculated as follows:

- [embedded customer Import fixed charge in p/day] = [Import fixed charge at the boundary] x [installed capacity of the embedded customer's Import/MPAN] / [total installed capacity of all embedded customers' Import/MPANs];
- [embedded customer Export fixed charge in p/day] = [Export fixed charge at the boundary] x [installed capacity of the embedded customer's Export MPAN] / [total installed capacity of all embedded customers' Export MPANs];[embedded customer Import capacity charge in p/kVA/Day] = [Import capacity charge at the boundary] x (Import agreed capacity at the boundary] / [total installed Import capacity of all embedded customers]); and
- [embedded customer Export capacity charge in p/kVA/Day] = [Export capacity charge at the boundary] x (Export agreed capacity at the boundary] / [total installed Export capacity of all embedded customers])

An example of how this is undertaken is shown in Attachment 6

4.44 This approach ensures that the boundary charges are allocated to each customer based on the proportion of their capacity compared to the total capacity installed. To charge based on each customer's installed capacity would be over-recovering the costs incurred if the total installed capacity on the network is greater than the agreed capacity at the boundary.

4.45 CDCM tariffs for customers connected to the PNO network at EHV are determined in accordance with Schedule 16, save that lower voltage elements are excluded e.g., where the PNO's network is connected at an EHV/HV substation, the costs associated with the LV customer, LV network, LV substation and HV network levels are excluded.

4.46 To overcome the concern raised over capacity and reactive power charges raised by the proposer under paragraph 3.13(d), 3.13 (g) and responders to the first consultation (Attachment 2), an alternative approach suggested in the first consultation is being adopted where both elements are added to the fixed charge as indicated in the following paragraphs.

4.47 The capacity charge elements (p/kVA/day) for half-hourly site-specific settled customers connected to PNO Networks 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 as determined under Schedule 16.

4.48 Reactive power charge elements (p/kVArh) for half-hourly site-specific settled customers connected to PNO Network are added 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 as determined under Schedule 16, and dividing by the number of days in the charging year.

Q3: Do you have any comments on the EDCM solution?

Introduction

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4.49 There was support within the Working Group to develop two solutions for fully settled arrangements within the CDCM for further consideration by parties. The first being to provide a rebate on request from the PNO and the second to introduce new tariffs to be charged to the embedded suppliers, see paragraph 4.27 and 4.28 above.

Fully Settled - CDCM Specific to Solution A (Rebate)

4.50 For fully settled metering installations solution A is to introduce a rebate to the PNO. This will be produced by initially creating a tariff which is different to the 'normal' CDCM tariffs as set out below:

- the lower voltage elements are excluded as follows e.g., where the PNO network is connected to the HV network, the costs associated with the LV customer, LV network and LV substation levels are excluded;
- the capacity charge element form part of the fixed charge (calculated as per paragraph 4.47 above);
- the reactive charge element also forms part of the fixed charge (calculated as per paragraph 4.48 above);
- The residual for these rebate tariffs should be calculated by taking the residual for the corresponding all-the-way tariff and multiplying by the ratio of the Forward Looking Charge calculated using the rebate tariffs to the Forward Looking Charge calculated using the all-the-way tariffs for each customer group. This ensures that the reduction in the residual charge aligns to the reduction in the Forward Looking Charge.

  [Residual surplus or shortfall for Licence Exempt Systems customers] = [Residual surplus or shortfall for all-the-way customers] × ([Forward Looking Charge from License Exempt System tariffs]) / ([Forward Looking Charge from all-the-way tariffs])

  As no customers are allocated to these tariffs in the CDCM, this step is performed after the revenue matching step has been completed.

4.51 For NHH settled or HH Aggregate settled users connected to the PNO network a rebate is calculated in £/customer/year for each customer group and each voltage of connection of a PNO network as follows:

a) The average kWh usage per customer per year in each timeband is determined from the DNO Party's volume forecast for that customer group;

b) The average charge for that customer group is calculated by applying the DNO Party's tariff to the usage derived under part a).

c) The average charge applicable for a customer in that customer group connected to a PNO network with that voltage of connection is calculated by applying the tariff created under paragraph 4.50 above to the usage derived under part a).

d) The rebate per customer per year is calculated as the result of part b) less the result of part c).

e) The rebate shall be capped such that a customer connected to a Licence Exempt System will not be charged more than a customer connected directly to the Distribution Network.

For HH Site Specific settled users connected to PNO networks, a rebate is calculated in £/customer/year for each customer by applying the tariff calculated under paragraphs 4.50 above to that customer's usage data and subtracting this total from the amount billed in respect of that

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customer. The rebate shall be capped such that a customer connected to a Licence Exempt System will not be charged more than a customer connected directly to the Distribution Network.

4.52 The Working Group recognise that issuing rebates will (all other things being equal) result in DNOs not recovering their full target revenue. As noted in the first consultation this can be resolved by either treating the rebate as negative UoS revenue and allowing the over/under-recovery 'correction' process to correct for it, or by introducing a new pass-through term in the CRC2B of the licence. It is anticipated that such rebates initially would form part of the correction process.

4.53 The Working Group have considered customers that have export MPANs. The view is that there will be no negative rebate (i.e charge) to PNOs for any export MPANs.

Q4: Do you have any comments on the rebate solution?
Q5: What are your thoughts on customers that export within the PNO Network, should there be a negative rebate?

4.54 The Working Group recognise that although the method of calculating the tariffs may be considered within the vires of DCUSA, mandating a process between the PNO and the Distributor would not be since PNOs are not Parties to the DCUSA.

4.55 However, the Working Group discussed whether a process could be added to Schedule 16 similar to that of Part 3 Network Unavailability Rebate Payments. This would provide some form of visibility amongst others of such a scheme existing.

4.56 The suggested text caters for who can claim and from when, together with providing evidence of meeting the criteria to be able to claim through to when to expect payment. The relevant extract from the legal text is shown below:

Part 5 — Licence Exempt System rebate scheme

This Part 5 sets out the process for providers of Licence Exempt Systems to claim a rebate where the connections within each Licence Exempt System are Fully Settled

The rebate comes into effect on [01 April 2022] and is calculated in accordance with either Paragraph 88E (for NHH settled or HH Aggregate settled users) or Paragraph 88F (for HH Site Specific settled users) of this schedule.

For a rebate to be granted, the provider of each Licence Exempt System must contact the Distribution Business and provide sufficient evidence that they meet the criteria of a Fully Settled Metering arrangements. For the avoidance of doubt there is no rebate available for Shared or Difference Metering arrangements associated with a Licence Exempt System.

Unless otherwise agreed with the Distribution Business, the rebate will be calculated on an annual basis (1st April - 31st March) and payments made shortly after the end of each year.

Note: The date in square brackets will be the implementation date for DCP 328.

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How regularly should the rebate be billed?

4.57 As stated above, the Working Group view is that the rebate will be calculated on an annual basis (1st April - 31st March) and payments made shortly after the end of each regulatory year, unless otherwise agreed. This allows for some flexibility between both parties especially if the rebate is substantial and also avoids minimum payment conditions.

Retrospective claims

4.58 The Working Group propose that retrospective claims can be made back to either the date of implementation of this CP; or up to a maximum of six years (five years in Scotland) from the date of the request, whichever is the shorter.

LC14 statement

4.59 The Working Group proposes that this process should form part of the LC14 statement, in order to provide as much visibility as possible.

Q6: 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?
Q7: Do you agree the rebate should be billed annually? If not, please provide reasons

Fully Settled - CDCM Specific to Solution B

4.60 For fully settled metering installations solution B is to introduce a set of tariffs specific to PNO networks and the level of connection to the Distribution network. Where such instances occur, Suppliers will need to replace the existing tariff with the appropriate new tariff.

4.61 The process is similar to that of the rebate solution apart from the last step i.e. to create the rebate. The tariffs differ to the normal tariffs as set out below:

- the lower voltage elements are excluded e.g. where the PNO network is connected to the HV network, the costs associated with the LV customer, LV network and LV substation levels are excluded;
- the capacity and reactive charge elements form part of the fixed charge (calculated as per paragraph 4.47 and 4.48 above); and
- For the calculation of the residual the volumes for these customers should be scaled by multiplying by the ratio of the Forward Looking Charges calculated using the new tariffs to the Forward Looking Charges calculated using the all-the-way tariffs for each customer group. This ensures that the reduction in the residual charge aligns to the reduction in the Forward Looking Charge.

  [Consumption for Licence Exempt Systems customers for revenue scaling] = [Consumption for Licence Exempt Systems customers] × ([Forward Looking Charges from License Exempt System tariffs]) / ([Forward Looking Charges from all-the-way tariffs])

4.62 The tariffs shall be charged to each supplier within the PNO network based on the Settlement data received in respect of the Settlement meter at each Metering Point within the PNO network, and is dependent on the voltage of the point of connection of the PNO network to the Distribution System

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(i.e. the PNO boundary), being either LV network, LV substation or HV. A set of tables have been created within the Schedule 16.

Q8: Do you have any comments on the tariff solution for fully settled metering installations?'

Solution preference for fully settled sites in the CDCM

4.63 The Working Group have proposed two solutions for fully settled metering arrangements discussed earlier in the consultation and seek views on which one is your preference.

Q9: Which solution do you support and why? Solution A or Solution B.

Complex Sites

4.64 The DCP359 Working Group descoped 'complex sites' from its change proposal looking at residual charges, citing that they needed to be considered at the same time as the forward-looking charges and which was out of scope of DCP359 and indeed the TCR.

4.65 The approach adopted by the Working Group is to use the definition of complex site contained within the BSC in order to follow existing industry terminology and understanding or such a term.

4.66 The BSC define both difference metering and shared metering arrangements as a complex site including those where such an arrangement exist within a private network. However, a fully settled site on a private network is classed as an Associated Distribution System i.e. each individual connection is treated in the same way as a direct connection to the distribution network.

4.67 The Working Group discussed and agreed that there was no reason to change the definitions of Single Site or Final Demand Site for complex sites within a private network or for those classed as an Associated Distribution System.

4.68 In all instances, be they a complex site or classed as an Associated Distribution System, the definition of a Single Site refers to a single connection agreement (whether a Bespoke Connection Agreement or one created via the National Terms of Connection). Either of these is an agreement between the customer (or in this instance the PNO) and the Distributor at the boundary connection and not with each customer within the boundary, so the definition of Single Site covers all of them together irrespective of type of metering arrangement and as such the decision on whether the Single site is a Final Demand Site or Non-Final Demand Site needs to be made collectively and not individually.

4.69 For ease of reading the definitions of Single Site, Final Demand Site and Non-Final Demand Site currently held in DCUSA as introduced by DCP359, and (in respect of Final Demand Site only, which moved from Schedule 32 to Section 1A) later amended by DCP380, are detailed below:

Final Demand: *means electricity which is consumed other than for the purposes of generation or export onto the electricity network.*

Final Demand Site: *means: (a) Domestic Premises; or (b) a Single Site (as defined in Schedule 32) at which there is Final Demand, as determined in accordance with Paragraphs 1.10 and 5 of Schedule 32.*

1.10 The DNO/IDNO Party will use the criteria in the table below to determine whether a Single Site is considered to be a Final Demand Site or a Non-Final Demand Site, and therefore whether or not to apply the residual fixed charge to that site.

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Criteria	Meets the criteria	Outcome
DNO/IDNO Party has been provided with valid certification that a Single Site is an Non Final Demand Site	*Yes*	*Single Site is a Non-Final Demand Site*
	No	*Single Site is a Final Demand Site*

Non-Final Demand: *is a Single Site at which either or both Electricity Storage* and/or Electricity Generation occurs (whether the facility(ies) at the site are operating or being commissioned, *repaired or decommissioned), and that:*

(a) has an export MPAN and an import MPAN with associated metering equipment which only measures export from Electricity Storage and/or Electricity Generation and import for or directly relating to Electricity Storage and/or Electricity Generation (and not export from another source and/or import for another activity); and

(i) if registered in an MPAS Registration System, is subject to certification from a Supplier Party that the site meets the criteria in paragraph (a) above, which certificate has been provided to the DNO/IDNO Party; or

(ii) if registered in CMRS, is subject to certification from the Customer (or its CVA Registrant) that the site meets the criteria in paragraph (a) above, which certificate has been provided to the DNO/IDNO Party

Single Site: *means one or more Non-Domestic Premises that are connected to the distribution system pursuant to a single Connection Agreement (whether a Bespoke Connection Agreement or one created via the National Terms of Connection*).

4.70 Complex sites connected directly to the Distribution Network are not considered to be in scope of this CP. There is a separate change proposal (DCP388) to consider such arrangements. This has been raised due a request under the DCP359 Authority decision to do so. Concern was raised that if the definitions do change in the new change proposal it will have a consequential impact on the outcome of this change. It was accepted that this is the nature of any change proposal.

4.71 A further concern was that there are a number of change proposals both in the DCUSA and in the Connection and Use of System Code (CUSC), and a perceived lack of clarity received from the Authority on the approach to complex site arrangements. Clarification on this and on a potential licence concern is contained within paragraph 4.86 to 4.91 below.

Q10: Do you agree with the approach to consider complex site based on the definitions agreed in DCP359?

Residual Charges

4.72 Similarly, residual charges for private networks were also de-scoped from DCP359 on the basis that they need to be considered alongside the forward looking charges as part of this Change Proposal. The approach adopted for each metering arrangement follows on from the decisions made on the

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forward looking charges approach. To enable compliance with the TCR, the residual is calculated and allocated to private networks at 'single site' level.

Difference Metering and shared metering arrangements (CDCM and EDCM)

4.73 For difference metering and shared metering, a single residual charge applies at the boundary, with the charging band allocated based on the agreed capacity at the boundary. This approach is the same as for any connection to the distribution network.

Fully settled metering arrangements (EDCM)

4.74 For fully settled metering arrangements in the EDCM a set of nominal boundary tariffs are created which are then split between the embedded customers and charged to the embedded Suppliers. The residual is allocated to the boundary tariff using the same process as for all other EDCM customers, with the charge shared between the embedded customers as part of the step to split the fixed charge. This ensures that the same level of residual is applied as if there was one connection at the boundary.

Fully Settled metering arrangements - CDCM Specific to Solution A

4.75 The Working Group agreed that the residual charge should receive the same percentage reduction in the revenue before matching from the rebate tariffs to that of the revenue before matching from all the ways tariffs for each customer group on a band by band basis. This is achieved by the following formula:

$$[Rebate\ residual\ charge] = [ATW\ residual\ charge] \times \frac{[revenue\ before\ matching\ from\ rebate\ tariffs]}{[revenue\ before\ matching\ from\ ATW\ tariffs]}$$

4.76 As there are no customers or volumes allocated to the rebate tariffs in the CDCM then this calculation can be performed after the revenue matching step.

Fully Settled metering arrangements - CDCM Specific to Solution B

4.77 For the calculation of the residual the volumes for these customers should be scaled by multiplying the ratio of the revenue before matching calculated using the new tariffs to the revenue before matching calculated using the all-the-way tariffs for each customer group. This is achieved by the following formula:

$$[LES\ volumes\ for\ residual\ allocation] = [LES\ Volumes] \times \frac{[revenue\ before\ matching\ from\ LES\ tariffs]}{[revenue\ before\ matching\ from\ ATW\ tariffs]}$$

4.78 By scaling the Licence Exempt System (LES) volumes in the revenue matching step this removes any unintended consequences of scaling the volumes when the IDNO discount is applied to the volumes and ensures that the reduction in the residual charge aligns to the reduction in the revenue before matching for these customers.

4.79 The Working Group is seeking views on the proposals for calculating residual charges.

Q11: Do you agree with the proposed methodology for calculating residual charges? If not, please provide your rationale

Competition Law

4.80 In the first consultation, one respondent raised a concern regarding evidence that the Working Group has considered whether competition law should be considered when assessing options for the charging arrangements between DNOs and private networks operators with competition in supply

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(see Attachment 2). Competition law was a key factor in determining the LDNO methodology and determination is needed as to whether the same competition law restrictions apply, and if they do, whether the proposals comply with such restrictions.

4.81 The Working Group recognised that this CP may improve the current situation but agreed to seek legal advice.

4.82 In summary, the legal advice from the DCUSA lawyers stated that it is likely that an AEC (as efficient competitor) test be undertaken by the distributors. The response is shown below:

"…… the legal position on margin squeeze remains unchanged since we last looked at it in respect of DCP266.

Therefore, where an undertaking (eg a DNO) has: (a) a dominant position in an upstream market (eg higher-voltage networks); and (b) competes with its customers in a downstream market (e.g. licence exempt networks within an industrial park), then there is potential for the DNO to breach competition law by abusive margin squeeze. The central issue to determine in such cases is whether a downstream customer (which is as efficient as the dominant undertaking) could operate profitably on the basis of: (a) the downstream price charged by the downstream arm of the dominant undertaking to its end customers; and (b) the upstream price charged by the dominant undertaking to its downstream competitors (referred to as the "AEC test").

To be sure on this point, the DNOs would need to undertake this economic analysis. For completeness, it is also possible to argue that a charging approach is objectively necessary or indispensable to achieving efficiency gains, which would give rise to consumer benefits outweighing any adverse effects, but this defence is based on a high evidential threshold, and economic analysis would be necessary to demonstrate the case."

4.83 In DCP266 change declaration it stated that neither the Working Group, nor the Panel can compel the DNOs to undertake a robust AEC test (the test indicated as necessary in the legal advice) without detailed access to information that would be considered commercially and competitively sensitive. • So, it is only the DNOs themselves that could individually undertake such a test and therefore it was suggested that either, the DNOs undertake an AEC test during the voting period to assist in their decision to either accept or reject to the change or potentially prepare for a request to supply the relevant information to Ofgem, if they were to decide to carry out the test themselves.

4.84 The Working Group are suggesting that this approach be adopted post this consultation.

4.85 The legal response in relation to DCP 266 can be found within the DCP 266 Change Report.

Ofgem clarification on potential licence concerns raised by the Proposer

4.86 The Proposer raised a concern over a potential conflict with the distribution licence. The licence is not intended to develop tariffs for customers on a private network and in doing so – and in hindsight – the Proposer asserts that a DNO Party cannot satisfy its licence obligations without creating a licence conflict.

4.87 The Proposer requested Ofgem guidance because this CP would result in a DNO Party being required to do something (i.e the calculation of UoS charges for customers behind a private network boundary) via a code that the licence does not specifically contemplate a DNO Party doing, in the way in which Designated Properties and Designated EHV Properties are defined (as defined in Standard Licence Conditions (SLCs) 13A and 13B respectively).

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4.88 It is the Proposer's view that, whilst this CP seeks to extend the application of Schedules 16 to 18 beyond Designated Properties and Designated EHV Properties respectively, doing so is beyond the remit of the distribution licence.

4.89 One argument put forward was by placing this in a code (which parties must comply with and failure to do so by a DNO Party results in that DNO Party being in breach of its licence), a DNO Party is meeting both its licence obligations and additional obligations contained within the code.

4.90 The Proposer recognised the conflict between licence and code obligations, but asserted that this CP would, as a minimum, contradict Relevant Objectives (a), and probably (c) and (d) (depending on whether the definition of Distribution Business includes the provision to calculate UoS charges for customers that are not Designated Properties or Designated EHV Properties[11]), of the charging methodologies as set out in SLC13A and SLC13B – for reference, these Relevant Objectives are consistent with DCUSA Charging Objectives 1, 3 and 4 – therefore there is an explicit contradiction between the DCUSA and distribution licence.

4.91 As a result, the Proposer asserted that it was essential to seek Ofgem guidance, which would ultimately be required to facilitate an Authority decision on this CP – it was noted that guidance would not likely be received prior to an Authority decision.

Any further considerations

4.92 The Working Group would like to understand whether there are any unintended consequences with any of the proposals specifically any impact not yet identified on Independent Distribution Network Operators.

Q12: Are there any unintended consequences associated with either solution with consideration given to any impact on Independent Distribution Network Operators?
Q13 (Mandatory for DNO Party's only, optional for other DCUSA Parties): Are there any unintended consequences associated with DCP328 and licence obligations?

5 Legal Text

Proposed Legal Text

5.1 The DCP 328 Legal Text can be found in Attachment 11 of this consultation.

[11] Distribution Business in this context, and as defined in the distribution licence, means "the distribution of electricity through the licensee's Distribution System", and does not (in the Proposer's view) include behind private networks. As such, a DNO Party is likely prohibited from calculating charges applicable behind private networks in accordance with SLC29, which requires that a DNO Party "must not conduct any business or carry on any activity other than an activity of the Distribution Business" other than where explicitly allowed under SLC29 (which it is not). It should be noted that the term Distribution Business does provide the vires for the Authority to consent that activities carried out by the DNO Party can stray from the Distribution System, and the Proposer believes that this would be needed, as a minimum requirement.

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Common to both solutions

Metering Data Option 1

5.2 This change affects clause 29 – metering equipment and metering data by including obligations on Distributors to:

- Create a non-Settlement MPAN and provide to the boundary supplier where there are difference metering arrangements or the primary Supplier where there are shared metering arrangements.

and on Suppliers to:

- Send gross metering data on the non-Settlement MPAN in the same timescale associated with Settlement MPANs; and
- Suppliers to allow the boundary Supplier or the primary Supplier to aggregate their metering data.

Metering Data Option 2

5.3 This change affects clause 29 – metering equipment and metering data by including obligations on Distributors to:

- Aggregate the metering data of both the boundary MPAN and embedded MPANs where there are difference metering arrangements and bill the boundary Supplier or aggregate the metering data for the primary MPAN and secondary MPANS where there are shared metering arrangements and bill the primary Supplier.

and on the Suppliers to:

- Allow the Distributor to aggregate their metering data.

5.4 A new clause has been added to Schedule 16 regarding difference metering and shared metering arrangements and being charged to the supplier at the Distributor's boundary or the primary Supplier based on the units imported or exported at the boundary between the Distributor's network and the PNO network. No charges will be applied by the Distributor to the boundary Settlement data received by the Distributor, or to the Settlement data received in respect of any Settlement meters within the PNO network.

5.5 New clauses added to Schedule 17 and 18 relating to:

- Difference metering and shared metering and who is charged and not charged similar to paragraph 5.3 above; and
- The introduction of new tariffs and how they will be derived.

Specific to Solution A

5.6 Schedule 16 has been amended to cater for how rebates are to be calculated for PNO networks by creating the relevant tariffs and then calculating a £/Customer/year value based on voltage of connection.

5.7 Schedule 16 has been amended to demonstrate that the residual for these rebate tariffs should be calculated by taking the residual for the corresponding all-the-way tariff and multiplying by the ratio of the revenue before matching calculated using the rebate tariffs to the revenue before matching calculated using the all-the-way tariffs for each customer group.

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Specific to Solution B

5.8 Schedule 16 has been amended to cater for how new tariffs are to be calculated for PNO networks with additional tables being included indicating the tariffs at different voltage levels of connection.

5.9 Schedule 16 has been amended to demonstrate that for the calculation of the residual the volumes for these customers should be scaled by multiplying the ratio of the revenue before matching calculated using the new tariffs to the revenue before matching calculated using the all-the-way tariffs for each customer group.

Methodology changes

5.10 Changes to the CDCM and EDCM methodologies have been produced **(see Attachment 8).**

Consequential changes

5.11 The Annual Review Pack will be amended to a later version number. Although the legal text will cater for this the actual document will not be amended until the change report stage.

Q14: Do you have any comments on the legal text

6 Relevant Objectives

Assessment Against the DCUSA Objectives

6.1. For a DCUSA CP to be approved it must be demonstrated that it better meets the DCUSA Objectives. The objectives identified by the Proposer that are impacted by this change are the charging objectives.

DCUSA Charging Objectives	Identified impact
☐ 1 that compliance by each DNO Party with the Charging Methodologies facilitates the discharge by the DNO Party of the obligations imposed on it under the Act and by its Distribution Licence	None
☐ 2 that compliance by each DNO Party with the Charging Methodologies facilitates competition in the generation and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity or in participation in the operation of an Interconnector (as defined in the Distribution Licences)	Positive
☐ 3 that compliance by each DNO Party with the Charging Methodologies results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the DNO Party in its Distribution Business	Positive
☐ 4 that, so far as is consistent with Clauses 3.2.1 to 3.2.3, the Charging Methodologies, so far as is reasonably practicable, properly take account of developments in each DNO Party's Distribution Business	Positive

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☐ 5 that compliance by each DNO Party with the Charging Methodologies facilitates compliance with the Regulation on Cross-Border Exchange in Electricity and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulators.	None
☐ 6 that compliance with the Charging Methodologies promotes efficiency in its own implementation and administration.	Negative

6.2. The Proposer (in the original CP and subject to resolution of the conflict between this CP and the distribution licence – see paragraphs 4.86 to 4.91) believed that this CP will have:

- **Charging Objective one**: no impact.
- **Charging Objective two**: better met, as the change will ensure that competition to supply customers connected to private networks is not distorted by the application of inappropriate UoS charges in respect of some or all customers connected to private networks.
- **Charging Objective three**: better met, as the change will ensure that the charges faced by multiple Suppliers supplying customers on a private network are broadly equivalent to the charges faced by a single Supplier supplying the private network operator on an equivalent site without competition in supply.
- **Charging Objective four**: better met, as DNOs are seeing increasing volumes of requests to facilitate competition in supply on private networks. Without the change and the regulatory clarity it seeks to create, there is a risk of a divergence in application of the common charging methodologies across DNO licensees.
- **Charging Objective five**: no impact.
- **Charging objective six:** perhaps not as well met, as the change may introduce additional complexity into the charging arrangements. This is considered necessary to ensure cost-reflectivity is maintained.

Q15: Do you believe that the DCUSA Charging Objectives are better facilitated by this CP? Please provide your rationale

7 Impacts & Other Considerations

Does this Change Proposal impact a Significant Code Review (SCR) or other significant industry change projects, if so, how?

7.1 Within the Ofgem decision letter for DCP 359 (Ofgem Targeted Charging Review Implementation: Customers – who should pay?), the following was stated:

"Under DCP359, customers connected to complex sites and private wires that currently receive a residual charge will continue to do so. DCP328 focuses on private networks; if the proposed solution for DCP328 does not apply to complex sites (that are not part of private networks), we would expect a party to propose a modification to address residual charging for such complex sites. For the avoidance of doubt, nothing in this letter in any way fetters our discretion with respect to DCP328".

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7.2 This CP is delivering private wire methodology including residual charges and complex sites contained within them. It is noted that there is a new CP that has been raised to facilitate appropriate residual charging for sites with a mix of final and non-final demand (DCP 388[12]).

7.3 It is also noted that CMP363 & CMP364[13]: TNUoS Demand Residual charges for transmission connected sites with a mix of Final and non-Final Demand has been raised by NGESO to clarify the TNUoS Demand Residual charging arrangements for transmission connected sites that have a mix of Final and non-Final Demand in the CUSC.

Impact assessment

CDCM Impact Assessment

7.4 The CDCM impact assessment sets out the impact of DCP 328 on all outputs of the CDCM for the 2022/23 charging year. Inputs were taken from published ARP models for the 2022/23 charging year and a Working Group assumption that 0.5% of customers are LES-connected for the sake of the impact assessment, and that the breakdown across different LES boundaries should be a third LV, a third HV/LV and a third HV.

Impact on revenue recovered

7.5 Options A and B lead to changes in expected revenue recovered from the CDCM.

7.6 Option A explicitly ignores the impact of giving LES rebates on revenue recovery – leaving the remainder to be resolved by a balancing term in the following charging year. Expected net revenue is therefore always lower than the baseline under Option A. The scale of this under-recovery ranges between -0.05% and -0.12% of baseline revenue under the volume assumptions provided by the working group (c. £5 million in total across all fourteen DNOs).

7.7 Option B adjusts the volumes used in revenue matching downwards to account for the share of the residual for which LES customers are not chargeable. Expected net revenue returns to levels approximately, but not exactly, equal to the baseline. For example, the difference in net revenue between Option B and the baseline ranges between +/- 0.01% under the volume assumptions provided by the working group (c. £0.15 million in total across all fourteen DNOs).

Comparison between LES and all-the-way bills

7.8 Typical bills under Options A and B are approximately the same for all tariffs – with only slight differences arising from revenue matching and rounding (especially for Option A).

7.9 The scale of the difference between LES and ATW tariffs can fluctuate significantly between different tariffs and / or DNOs due to the different costs which apply at network levels below the LES boundary.

Impact on a typical LES customers

7.10 Although Options A and B give very similar bills for LES customers with typical volumes, their impacts diverge for HH Aggregated customers whose volumes are not equal to the average for their customer group. This only affects HH Aggregated tariffs because Option A expresses rebates for these

[12] DCP388 - Amendments to Facilitate Appropriate Residual Charging for Sites with a Mix of Final and Non-Final Demand

[13] CMP363 & CMP364 'TNUoS Demand Residual charges for transmission connected sites with a mix of Final and non-Final Demand & Definition changes for CMP363' | National Grid ESO

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customers as a constant £/customer/year regardless of their actual usage, whereas rebates for Site Specific tariffs are based on customers' own volumes.

Impact on non-LES customers

7.11 Option A doesn't explicitly affect revenue matching, so ATW and LDNO tariffs are unchanged within the charging year. However, residuals will rise in the following year to make up for LES rebates granted in this year.

7.12 Option B explicitly changes revenue matching, so ATW and LDNO tariffs must increase to offset the revenue lost with respect to costs below LES boundaries. Using volume assumptions suggested by the working group, the difference in ATW typical bills relative to the baseline ranges between 0% and 0.16%, depending on the DNO and tariff. Note that the assumed share of LES customers by tariff can also affect the allocation of the residual between tariffs as well as the overall amount.

Comparison with LDNO tariffs

7.13 LES tariffs are similar in kind to LDNO tariffs, which also aim to exclude costs/assets associated with network levels below a boundary. LDNO tariffs are calculated in the PCDM as a percentage of ATW tariffs and are typically stable from year-to-year and apply equally to tariffs at the same network level.

7.14 By contrast, LES tariffs are highly dependent on the distribution of costs between network levels in the CDCM for each tariff. The share of the residual paid at a LES boundary is also determined by the ratio between LES and all the-way pre-matching revenues, which are dependent on the ratio of average volumes recorded for that customer category. LES tariffs can therefore be greater or lesser than LDNO tariffs for the equivalent boundary level.

7.15 The Working Group would like respondents to consider, based on your portfolio, whether the impacts in this area are material.

7.16 The CDCM Impact Assessment can be found in **Attachment 9**.

EDCM Impact Assessment

7.17 For the EDCM there is no impact on any existing boundary tariffs from the changes to the model for the proposed solutions for all metering types.

7.18 For the solution for difference metering and shared metering the boundary tariff calculated will be in line with the tariff calculated in the current models so there is no impact on the tariff for that site or for any other sites in the EDCM. The only impact from this will be that there will no longer be multiple fixed or capacity charges levied for each MPAN, however this is an impact on collected revenue, not on the tariffs calculated within the models.

7.19 For the solution for fully settled metering there is a boundary tariff calculated which is then shared between the embedded customers in a separate calculation. As the boundary tariff is still calculated in the same way as prior to this change, there will be no impact on the tariff for that site or any other sites in the EDCM. The split of the fixed charge tariff between the embedded MPANs ensures that the same revenue is billed as if the site was billed as a single MPAN at the boundary. Examples of this in practice are given along the explanation of the EDCM method in Attachment 6.

7.20 A summary of the DCP 328 modelling work can be found in Attachment 7.

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8 Implementation

8.1. The proposed implementation date for this CP is 01 April 2022 This would mean that the Authority would need to issue a direction that the requisite period of notice (15 months) for publishing DUoS charges need not apply to this change proposal (DCUSA Section 2A, Clause 19.1B).

19.1B The periods of notice described in Clause 19.1A shall apply unless the Authority directs the Company that those periods of notice need not apply. Where the Authority directs the Company that those periods of notice need not apply, the notice period shall be 40 days (without prejudice to any longer notice requirements prescribed by the Distribution Licence).

Q16: If this change was approved, when should it be implemented? Please provide your rationale if different to April 2022.

9 Consultation Questions

9.1 The Working Group is seeking industry views on the following consultation questions:

Number	Questions
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.
2	Which metering data option to you prefer? Please provide your rationale, including any cost impacts.
3	Do you have any comments on the EDCM solution?
4	Do you have any comments on the rebate solution?
5	What are your thoughts on customers that export within the PNO Network, should there be a negative rebate?
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?
7	Do you agree the rebate should be billed annually? If not, please provide reasons.
8	Do you have any comments on the tariff solution for fully settled metering installations?'
9	Which solution do you support and why? Solution A or Solution B.

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10	Do you agree with the approach to consider complex site based on the definitions agreed in DCP359?
11	Do you agree with the proposed methodology for calculating residual charges? If not, please provide your rationale.
12	Are there any unintended consequences associated with either solution with consideration given to any impact on Independent Distribution Network Operators?
13	(Mandatory for DNO Party's only, optional for other DCUSA Parties): Are there any unintended consequences associated with DCP328 and licence obligations?
14	Do you have any comments on the legal text?
15	Do you believe that the DCUSA Charging Objectives are better facilitated by this CP? Please provide your rationale
16	If this change was approved, when should it be implemented? Please provide your rationale if different to April 2022
17	Any other comments?

9.2 Responses should be submitted using Attachment 3 to dcusa@electralink.co.uk no later than, **XXXX**.

9.3 Responses, or any part thereof, can be provided in confidence. Parties are asked to clearly indicate any parts of a response that are to be treated confidentially.

Attachments

Attachment 1 – DCP 328 First Consultation Document

Attachment 2 – DCP 328 First Consultation Responses and Working Group Feedback

Attachment 3 – DCP 328 Consultation Response Form

Attachment 4 – Timeline and Party Obligations from DCP 158

Attachment 5 – DCP328 change proposal form

Attachment 6 – Example on how capacity and fixed charges are to be apportioned in the EDCM

Attachment 7 – DCP 328 Modelling Summary Documentation

Attachment 8 – DCP 328 Methodology models (Click here)

Attachment 9 – CDCM Impact Assessment (Click here)

Attachment 10 – DCP328 issue responses

Attachment 11 – DCP 328 Legal Text (Solution A and Solution B)

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