





DCUSA Change Declaration		At what stage is this document in the process?
<div>DCP 328:</div> <div>Use of system charging for private networks with competition in supply</div> <div>Raised on 15 August 2018 as a Standard Change</div>	01 – Change Proposal	
	02 – Consultation	
	03 – Change Report	
	04 – Change Declaration	
<div>Purpose of Change Proposal:</div> <div>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.</div>		
	<div>DCUSA Parties have voted on DCUSA Change Proposal (DCP) 328 with the outcome being a recommendation to the Authority as to whether or not the Change Proposal (CP) should be accepted. As DCP 328 is considered to be a Part 1 Matter, the recommendation will be issued to the Authority for their final decision.</div> <div>The DCUSA Parties consolidated votes are provided as Attachment 2.</div>	
	<div>For DCP 328, DCUSA Parties recommend to the Authority to:</div> <div><ul style="list-style-type: none"><li>Reject the proposed variation (solution); and</li><li>Reject the implementation date.</li></ul></div>	
	<div>DCUSA parties: Suppliers, DNOs and IDNOs</div> <div>Others: private network operators and customers connected to private networks.</div>	
	<div>Impacted Clauses:</div> <div>Clause 1 – definitions</div> <div>Clause 29 – metering equipment and metering data</div> <div>Schedule 16 - Common Distribution Charging Methodology</div> <div>Schedule 17 - EHV Charging Methodology (FCP Model)</div> <div>Schedule 18 - EHV Charging Methodology (LRIC Model); and</div> <div>Schedule 20 – Production of Annual Review Pack</div>	

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Any questions?

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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	07 October 2022
Change Report issued for Voting	10 October 2022
Party Voting Ends	31 October 2022
Change Declaration Issued to the Authority	01 November 2022
Authority Decision	TBC
Implementation	01 April 2024

# 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<sup>1</sup> 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<sup>2</sup> 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 3
- 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 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.

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<sup>1</sup> 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.

<sup>2</sup> [http://www.legislation.gov.uk/ukxi/2011/2704/pdfs/ukxi\\_20112704\\_en.pdf](http://www.legislation.gov.uk/ukxi/2011/2704/pdfs/ukxi_20112704_en.pdf)

- 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. After consideration of feedback received and further analysis by the Working Group, a solution has been defined based on the type of metering arrangement<sup>3</sup> that exists on the PNO network.

### **Solution**

#### Difference Metering

For difference metering installations in both the CDCM and the EDCM, Distributors charge the fixed and capacity charges to the boundary Supplier along with charges for all of the consumption on the PNO network. Any third-party Supplier is not charged by the Distributor even though metering data is received for each metering point within the PNO network.

#### Shared Metering

For Shared Metering installations in both the CDCM and the EDCM, Distributors charge fixed and capacity charges to the Primary Supplier along with charges for all the consumption on the PNO network. Any third party Supplier is not charged by the Distributor even though metering data is received for each metering point within the PNO network.

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<sup>3</sup> This is explained further in section 3.

#### Fully settled metering installations:

- charge the embedded Suppliers in the CDCM by creating new tariffs which only include elements of charging which relate to voltage levels provided by the Distributor and apply the capacity and reactive element within the fixed charge; and
- charge the embedded Suppliers in the EDCM by creating a boundary tariff and allocating the fixed (including a reactive element) and capacity charges included in that boundary tariff to each embedded Supplier based on the proportion of their capacity to that of the boundary capacity.

1.10. The proposed solution for difference metering suggested by DCP158<sup>4</sup> was for the boundary Supplier to provide gross boundary data. This is also being proposed within this change proposal and is also a requirement of the Primary Supplier where Shared Metering applies.

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<sup>5</sup>. The residual charges will be applied as follows:

- For difference metering and shared metering in both the CDCM and EDCM, a single residual charge applies at the boundary, with the charging band allocated based on the agreed capacity at the boundary.
- For fully settled metering arrangements in the EDCM a nominal boundary tariff including the residual element forming part of the fixed charge is created which is then split, as indicated within paragraph 1.9 above, between the embedded customers and charged to the embedded Suppliers.
- For the calculation of the residual charge, the volumes for fully settled sites in the CDCM are to 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.

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

2.1 DCP 328 has been designated as 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;

<sup>4</sup> DNO DUoS re EDNOs

<sup>5</sup> Ofgem Targeted Charging Review Implementation: Calculation of Charges

- ii. the distribution of electricity;
- iii. the supply of electricity; and
- iv. any commercial activities connected with the generation, distribution or supply of electricity.

2.2 DCP 328 has been designated as a standard change.

### Requested Next Steps

2.3 The Panel considered that the Working Group have carried out the level of analysis required to enable Parties to understand the impact of the proposed amendment and to vote on DCP 328.

2.4 The DCUSA Panel recommends that this CP:

- Be issued to Parties for Voting.

## 3 Why Change?

### Background of DCP 328

3.1. Elexon have a guidance document for Third Party Access to Licence Exempt Distribution Networks<sup>6</sup>. 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.

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<sup>6</sup> [Third Party Access to Licence Exempt Distribution Networks](#)

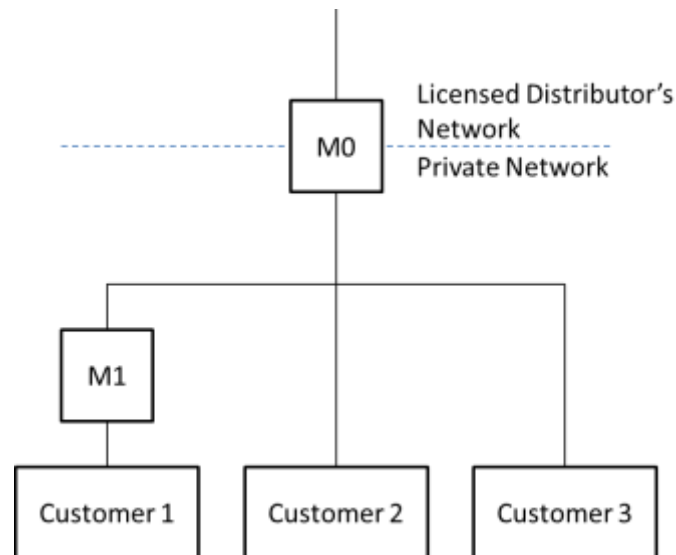


Figure 1 - competition in supply using difference metering

- 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.

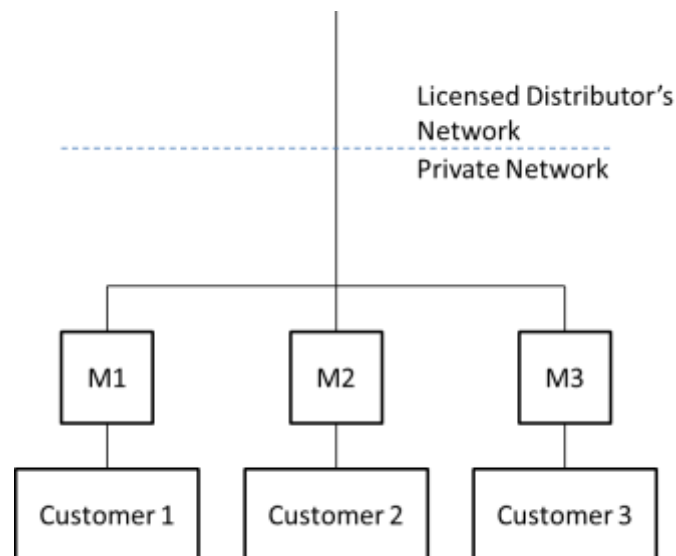


Figure 2 - competition in supply using full Settlement metering

- 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'.

- 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.

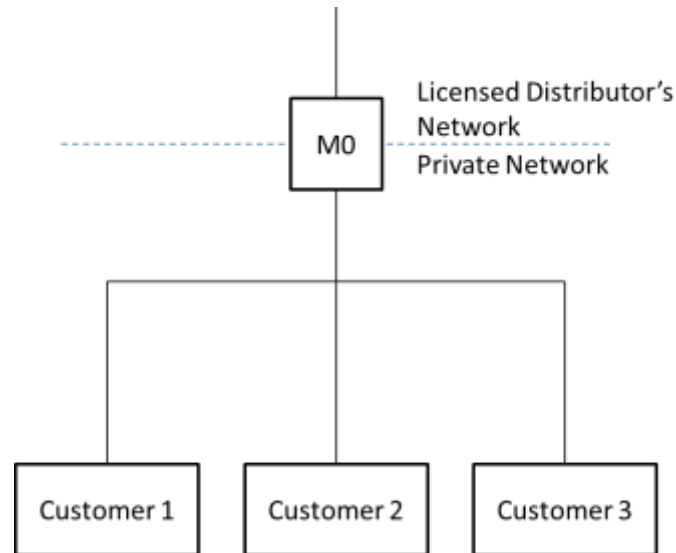


Figure 3 - competition in supply using shared metering

- 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 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 4) 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).
- 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 Change Report can be found in Attachment 5.

- 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 Solution

### DCP 328 Assessment

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

### DCP 328 Consultations

- 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 7.
- 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 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:
- 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.
- 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.

#### **Post First Consultation and Targeted Charging Review change proposals**

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

- Shared Metering arrangements;
- Refine the solutions to form part of a second 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;
- 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**

- 4.22 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. For shared metering arrangements, 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 Full Settlement metering arrangements with the solution to bill each Supplier.

- 4.23 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.
- 4.24 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<sup>7</sup> 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, as for similar customer types within the fully settled solution 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.
- 4.25 The Working Group agreed to progress with the solution for shared metering arrangements being similar to the difference metering approach i.e. bill the primary Supplier based on gross boundary metering data.
- 4.26 Within the second consultation respondents were asked if they agreed with the above approach. A majority of the respondents were supportive of the Working Group proposed approach to bill the Primary Supplier based on gross metered data from the boundary settlement meter for shared metering arrangements in preference to each Supplier being billed based on the fully settled solutions suggested in the first consultation.

#### Refined Solutions for Second Consultation

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

<b>Solution A</b>	<b>Difference metering</b>	<b>Fully settled metering</b>	<b>Shared metering</b>
<b>CDCM</b>	Charge the boundary Supplier	Rebate the PNO	Charge the primary Supplier
<b>EDCM</b>	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;

<sup>7</sup> The primary Supplier is responsible for the shared metering arrangements as per the BSC.



“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 was 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.

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

- 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<sup>8</sup>, 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.

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<sup>8</sup> Distribution Exempt Holder

- 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<sup>9</sup> Data Collector.**

- 4.34 The Distributor will create a non-Settlement MPAN<sup>10</sup> 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 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 required 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). The removal of this requirement avoids any further consequential changes due to such a closure<sup>11</sup>.

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

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<sup>9</sup> Note that the primary Supplier has an obligation to ensure that there is only one data collector to a shared metering system.

<sup>10</sup> the metering data from the boundary MPAN is reduced by the difference metering arrangement, so it is proposed to introduce a new MPAN which the data collector will use to provide the gross metering data for the Distributor to use to bill UoS charges. The data associated with the new MPAN will not enter settlements.

<sup>11</sup> The MRA is now closed and the MPAS address is managed by the Retail Energy Code



- 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 were keen to understand what the impact of the options for metering data would be to both systems and business processes associated with each option as part of the response to the option preferred.

### Fully settled arrangements (EDCM)

- 4.41 The second consultation 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 for the DNOs to use the Settlement metering data of each embedded customer within the relevant PNO network, as provided by the embedded Suppliers, 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.
- 4.43 The second step will be the allocation, by the DNOs, of the fixed charge (including the residual element) and capacity charge derived from the first step above to each embedded Supplier for both import and export charges for the relevant PNO network. These will be calculated as follows:
- $$[\text{embedded customer Import fixed charge in p/day}] = [\text{Import fixed charge at the boundary}] \times [\text{installed capacity of the embedded customer's Import/MPAN}] / [\text{total installed capacity of all embedded customers' Import/MPANs}];$$
  - $$[\text{embedded customer Export fixed charge in p/day}] = [\text{Export fixed charge at the boundary}] \times [\text{installed capacity of the embedded customer's Export MPAN}] / [\text{total installed capacity of all embedded customers' Export MPANs}];$$
  

$$[\text{embedded customer Import capacity charge in p/kVA/Day}] = [\text{Import capacity charge at the boundary}] \times (\text{Import agreed capacity at the boundary}) / [\text{total installed Import capacity of all embedded customers}];$$
 and
  - $$[\text{embedded customer Export capacity charge in p/kVA/Day}] = [\text{Export capacity charge at the boundary}] \times (\text{Export agreed capacity at the boundary}) / [\text{total installed Export capacity of all embedded customers}];$$

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 7), 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.

#### Fully Settled - CDCM Specific

- 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.

#### Solution A (Rebate)

- 4.50 For fully settled metering installations solution A suggested introducing a rebate to the PNO. This would 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 forms 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.

$$[\text{Residual surplus or shortfall for Licence Exempt Systems customers}] = [\text{Residual surplus or shortfall for all-the-way customers}] \times ([\text{Forward Looking Charge from License Exempt System tariffs}] / ([\text{Forward Looking Charge from all-the-way tariffs}]))$$

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 would be 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 would be 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 customer. It was suggested that the rebate would 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 was suggested that such rebates initially would form part of the correction process as the materiality is expected to be small.

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

#### **Solution B (Tariff)**

4.54 For fully settled metering installations solution B proposed 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.

4.55 The process is similar to that of the rebate solution apart from the last step i.e. to create the rebate. The tariffs differ from the all-the-way 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])

- 4.56 The tariffs would be charged to each Supplier within the PNO network based on the Settlement data received by the DNOs 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 (i.e. the PNO boundary), being either LV network, LV substation or HV. A set of tables have been created within the Schedule 16.

### Complex Sites

- 4.57 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.
- 4.58 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 of such a term.
- 4.59 The BSC define both difference metering and shared metering arrangements as a complex site including those where such an arrangement exists 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.
- 4.60 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.
- 4.61 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.
- 4.62 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.

Criteria	Meets the criteria	Outcome
DNO/IDNO Party has been provided with	Yes	Single Site is a Non-Final Demand Site

<i>valid certification that a Single Site is an Non Final Demand Site</i>	<i>No</i>	<i>Single Site is a Final Demand Site</i>
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**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).*

4.63 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.

### **Residual Charges**

4.64 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 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)**

4.65 For difference metering and shared metering, it was proposed that 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)**

4.66 For fully settled metering arrangements in the EDCM it was proposed that a set of nominal boundary tariffs are created by the DNOs 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

4.67 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:

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

4.68 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

4.69 For the calculation of the residual, it was proposed that 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:

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

4.70 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.

#### Competition Law

4.71 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 (see Attachment 7). 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.

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

4.73 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.”

- 4.74 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.
- 4.75 Within the second consultation, the Working Group therefore suggested that this approach be adopted by DNOs. The Working Groups final analysis regarding competition law can be found later in this Change Report.

### **Unintended Consequences**

- 4.76 Within the second consultation the Working Group asked respondents if they believed there were any unintended consequences associated with either solution with consideration given to any impact on Independent Distribution Network Operators. DNOs were also asked whether they believed there were any unintended consequences associated with DCP328 and licence obligations.

### **Ofgem clarification on potential licence concerns raised by the Proposer**

- 4.77 Within the second consultation 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.
- 4.78 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).
- 4.79 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.
- 4.80 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.
- 4.81 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<sup>12</sup>), 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.

4.82 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.

4.83 In relation to the above the following response was received:

*“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”.*

## Second Consultation

4.84 The Working Group issued a second consultation to parties on 4 June 2021. The aim of the second consultation was to ask the industry for views on the revised solutions proposed. There were twelve respondents to the second consultation comprising of eight Distributors, one Supplier, one Generator and two consultancy organisations. A copy of the second consultation and the Working Group response to comments received can be found in Attachment 8.

4.85 All of the second consultation questions and the Working Group summaries can be found below.

**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.**

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<sup>12</sup> 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.



- 4.86 The majority of the respondents were supportive of the Working Group proposed approach 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. One respondent noted that there may be a potential DCUSA sandbox application coming in relation to this subject. It was noted that this CP is based on the current version of DCUSA and therefore any existing sandbox application is out of scope. However, any future implemented changes will be taken into consideration as appropriate.

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

- 4.87 The majority of respondents were in favour of metering data option 1. One respondent noted that option 2 would require implementation of changes within DURABILL and that the cost would be anticipated to be in the region of £160k to £300k, split between all Durabill customers. The working group noted there would also be costs for updates to billing systems used by other DNOs/IDNOs.

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

- 4.88 The majority of respondents were comfortable with the proposed solution for the EDCM. One respondent raised a concern regarding potential disparity between charges of a PNO and an equivalent customer with a single meter.

**Q4: Do you have any comments on the rebate solution?**

- 4.89 A number of concerns were raised by respondents regarding the rebate solution (option A) such as what would a dispute process look like, the likelihood to add additional complication to current billing systems and potential to be an administrative burden. This option received less support than the tariff option B.

**Q5: What are your thoughts on customers that export within the PNO Network, should there be a negative rebate?**

- 4.90 Some respondents agreed that there should be no negative rebate if this solution progressed, however other respondents expressed some concerns. For example, one respondent noted 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. Another concern raised was in relation to 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.

**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?**

- 4.91 There were a number of comments received for consideration from the Working Group. For example, one respondent stated that if rebates are to be regarded as non-DUoS, it may be better for them to be covered in a separate schedule. Another concern raised was that PNOs do not accede to DCUSA and therefore the respondent was not convinced that this would be sufficient to alert PNOs to the fact that they might be eligible for a rebate.

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

- 4.92 There was agreement amongst respondents that the rebate should be billed annually, if the rebate solution is taken forward.

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

- 4.93 The tariff option B received the majority support within the consultation; however, some concerns were raised. One respondent noted that this solution would result in the introduction of a significant number of new tariffs. Another respondent noted that aggregate DUoS charges should be identical under all scenarios, including no competition in supply or a single site/customer and that they do not believe this would be achieved by the tariff solution for fully settled metering installations. They suggested 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.
- 4.94 One respondent raised concerns in relation to the way in which the tariffs are allocated to MPANs within distributors’ billing systems. This is generally done through the application of LLFCs, and they noted that this can be a burdensome task.
- 4.95 One respondent noted that DURABILL would be able to bill sites based upon the tariff described in the consultation document without any system changes being required. As an alternative solution they suggested using the MTC to identify where a customer is connected to a private network operator’s system, but acknowledged that this is likely to require changes to billing systems which will have both cost and lead time implications for the change.

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

- 4.96 Respondents’ views were very divergent, but the more favoured option was the tariff option B.

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

- 4.97 A majority of respondents agree with the approach to consider complex site based on the definitions agreed in DCP359. One respondent stated that potential future changes to the definition arising due to DCP388 should not (and cannot) be taken into account within this CP and another noted that the Working Group should also consider that the site remains a single site for the purposes of the TCR.

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

- 4.98 A majority of the respondents agreed with the proposed methodology for calculating residual charges. It was noted that the preference of one respondent would be to introduce an IDNO PCDM equivalent arrangement.

**Q12: Are there any unintended consequences associated with either solution with consideration given to any impact on Independent Distribution Network Operators?**

- 4.99 The following responses were received:

1. *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.*

*2. Yes, we have three main concerns in respect of both solutions which will have unintended consequences on IDNOs*

- 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.*
- 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.

- 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”.
3. 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.
  4. 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.
  5. 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.

The Working Group have considered the above responses in their analysis post the second consultation and further details can be seen later in this Change Report.

**Q13: (Mandatory for DNO Party's only, optional for other DCUSA Parties): Are there any unintended consequences associated with DCP328 and licence obligations?**

**4.100** One respondent noted the Proposer's concern that the proposed DCUSA changes are not currently underpinned by the Distributors' licence obligations and may create a conflict. They stated that they 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.

#### Q14: Do you have any comments on the legal text?

**4.101** One respondent noted that in the legal text it states that the capacity elements and reactive power elements will be allocated to the fixed charge based using an average kVA or kVArh. They requested clarity on why this decision was made.

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

**4.102** Respondents' views were very divergent. A third of the respondents considered that the Objectives would largely be better facilitated, a further third considered that the Objectives would largely not be better facilitated, and the remainder expressed a mixed view or no view.

**4.103** At a high level, the following table sets out which DCUSA Charging Objectives they believed were better facilitated.

Respondent	Charging Objective 1	Charging Objective 2	Charging Objective 3	Charging Objective 4	Charging Objective 6
1.					
2.			Negative		Positive
3.		Negative	Negative		
4.	Negative		Negative	Negative	
5.	Positive	Positive	Positive	Positive	Positive
6.		Positive		Positive	
7.		Positive	Positive	Positive	Negative
8.		Positive	Positive	Positive	Negative
9.	Neutral	Positive	Neutral	Positive	Positive
10.		Negative	Negative	Neutral	Negative
11.		Positive	Positive	Positive	Negative
12.		Positive	Positive	Positive	Negative

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

**4.104** Some respondents believed this date was ambitious and suggested April 2023 or April 2024 as alternatives. The Working Group decision on implementation is detailed in Section 7.

#### Q17: Any other comments?

**4.105** One respondent noted that they expect that elements of the solution may result in the disclosure of data not currently in the public domain. They asked for clarity to avoid any potentially commercially sensitive information being published.



### Working Group Conclusions and next steps

4.106 The Working Group identified a number of areas of further work having discussed the parties' responses to the second consultation:

- 4.106.1 Agree approach for shared metering arrangements;
- 4.106.2 Agree which Metering Data option should be used to support private networks where difference metering and shared metering exists;
- 4.106.3 Finalise the EDCM solution;
- 4.106.4 Agree whether to progress with the rebate option or the tariff option for fully settled CDCM arrangements and finalise preferred solution;
- 4.106.5 Finalise and agree decision regarding complex sites;
- 4.106.6 Finalise and agree decision regarding residual charging;
- 4.106.7 Provide final analysis regarding competition law concerns;
- 4.106.8 Consider the concerns raised in relation to unintended consequences
  - Impact assessment on LDNO tariffs
  - What tariff will be applied to an IDNO where an end customer is connected to the DNO via both an IDNO and private network
  - LES tariffs includes a discount network level at LV substation. This discount is not available within the PCDM
- 4.106.9 Provide final analysis in relation to potential licence condition conflicts
- 4.106.10 Consider published data and confidentiality

### **Decision on Shared Metering Approach**

**4.107** Most of the respondents were supportive of the Working Group proposed approach to bill the Primary Supplier based on gross metered data from the boundary settlement meter for shared metering arrangements in preference to each Supplier which was the fully settled solution suggested in the first consultation.

**4.108** After further consideration, the Working Group agreed to bill the Primary Supplier and therefore the solution for both difference metering and shared metering will be the same.

### **Decision on Metering Data Approach**

4.109 The Working Group consulted on two options. One option was to request the boundary Supplier's data collector to provide the aggregated data. The other option was for the Distributor to aggregate the Settlement data themselves.

4.110 A majority of respondents were in favour of metering data option 1. It was noted that option 2 would require implementation of changes within DURABILL and that the cost would be anticipated to be in the region of £160k to £300k, split between all DURABILL customers. The working group also noted there would be costs for updates to billing systems used by other DNOs/IDNOs.

4.111 Taking the above into consideration, the Working Group agreed to progress with metering option 1 which is for the Supplier's data collector to provide the aggregated data.

#### **Final EDCM Solution**

4.112 The EDCM solution that was proposed in the second consultation was supported by a majority of respondents and after review, the Working Group agreed that this was a suitable solution to take forward.

4.113 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.

4.114 For full settlement metering the solution is a two-step approach as described in 4.42 and 4.43 above.

#### **Agree whether to progress with the rebate option or the tariff option for fully settled CDCM arrangements and finalise preferred solution**

4.115 After consideration of the responses to the second consultation the Working Group agreed to progress with the tariff option for fully settled CDCM arrangements. There were a number of responses for and against both the rebate and the tariff option. The Working Group considered that the responses for the tariff option outweighed the other responses and agreed to take this option forwards.

4.116 The solution for fully settled CDCM arrangements is therefore to introduce a set of tariffs specific to PNO networks and the level of connection to the Distribution network as described in 4.54 to 4.56 above.

#### **Complex Sites**

4.117 The majority of respondents to the second consultation agreed with the approach to consider complex site based on the definitions agreed in DCP359. After further review the Working Group agreed that this was an appropriate approach especially since DCP388 'Amendments to Facilitate Appropriate Residual Charging for Sites with a Mix of Final and Non-Final Demand' is considering this area.

#### **Residual Charging**

4.118 As stated above, a majority of respondents to the second consultation agreed with the proposed methodology for calculating residual charges.

4.119 The approach adopted for each metering arrangement follows on from the decisions made on the forward-looking charges approach. To enable compliance with the TCR, the residual is calculated and allocated to private networks at 'single site' level.

#### **Final Analysis – Competition Law**

4.120 As detailed above, the Working Group sought legal advice in relation to competition law. In summary, the legal advice from the DCUSA lawyers stated that it is likely that an AEC (as efficient competitor) test should be undertaken by DNOs.

4.121 Similar to advice provided in relation to DCP 266 'The calculation and application of IDNO discounts', the Working Group, nor the Panel can compel the DNOs to undertake a robust AEC test without detailed access to information that would be considered commercially and competitively sensitive. Therefore, it is only the DNOs themselves that could individually undertake such a test and it is 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.

### Consider the concerns raised in relation to unintended consequences

#### Impact assessment on LDNO tariffs

4.122 It was noted that in some cases there were unintended consequences for PNO customers embedded within an LDNO network, whereby the revenue collected by the LDNO from the PNO customer could be less than the revenue collected by the DNO from the LDNO for that customer, resulting in negative revenue for the LDNO. In order to counteract this the working group gave consideration to adapting the solution for fully settled metering to include a floor in the fixed charge tariff element such that the total revenue calculated using the Licence Exempt System (LES) tariffs<sup>13</sup> and the average volumes for an PNO customer cannot be less than the revenue calculated using the equivalent LDNO tariff and the same average volumes, i.e. for an average customer the difference between the revenue collected by the LDNO from the PNO customer and paid by the LDNO to the DNO for that customer cannot be negative.

$$LES \text{ tariff} \times \text{Average LES volumes} > LDNO \text{ tariff} \times \text{Average LES volumes}.$$

4.123 The number of tariffs impacted by this and the number of MPANs connected to LDNOs on these tariffs was assessed and is expected to be minimal (further details provided in Section 6). The Working Group engaged with Ofgem regarding the introduction of a floor and the following key points were made:

- 1) it is believed that this problem should not be fixed through a CP which was initially intended to ensure UoS charges remain cost reflective when competition in supply is in place on private networks; and
- 2) DCP 266 suggested a similar approach and in Ofgem's decision letter they stated "We consider that an increase in the number of capped tariffs is not cost reflective, because the tariffs themselves are not cost reflective".

4.124 After further review and consideration of the points above, the Working Group agreed to remove the floor from the solution. It was suggested that IDNOs should send Ofgem confidential responses with their analysis of how it is going to impact their businesses.

#### Tariff to be applied to an IDNO where an end customer is connected to the DNO via both an IDNO and private network

4.125 The tariff to be applied to an IDNO where an end customer is connected to the DNO via both an IDNO and private network is the same tariff as if the end customer was connected directly to the IDNO.

4.126 The working group considered whether a set of nested tariffs should be introduced for invoicing IDNOs in the case where there are embedded private networks within an IDNOs network. After discussion with the modellers, it was agreed that this would not be taken forward as there was a concern that the solution

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<sup>13</sup> The DCUSA legal text uses the term Licence Exempt System or LES and means the same as PNO used within this change proposal.



may not make sense conceptually, due to a misapplication of LDNO discounts. The calculation of LDNO discounts implicitly assumes a relationship between the tariff associated with a subset of network level, and the cost of those network levels. The solution proposed applying the LDNO discounts to LES tariffs. The modeller's concern was that this approach does not provide a self-consistent method for calculating tariffs for LES customers serviced by LDNOs.

#### LES tariff discount at LV Substation level

- 4.127 Following the second consultation some changes have been made to the solution for fully settled metering. In the consultation responses it was noted that in option B there was a set of HV/LV level tariffs, which do not align to the available tariffs for LDNO connected customers. The working group agreed that this level should be removed, and the customers connected at this level should receive the LES HV tariffs.
- 4.128 This has been modelled and the impact assessment is included in Attachment 9. The variance to the calculated tariffs because of this change is minimal, with the exception that the customers connected at HV/LV level will now be charged the LES HV tariffs.

#### Licence Condition

- 4.129 The Working Group explored further whether the EU regulation (Article 37 of the 2009/72 Third Energy Package, para 6) eliminates the concerns mentioned in relation to Distributor Licence Conditions. The following legal advice was received:

*I note that a potential conflict with the distribution licence has been identified by the proposer. I have not previously been asked to consider this issue. Let me know if you want me to consider this issue generally.*

*In respect of the particular point identified regarding the EU Directives:*

- 1. Reference is made to Article 37 of EU Directive 2009/72. This Directive has actually been repealed, but it makes no difference as the same requirements now exist in Article 6 of EU Directive 2019/944. It is correct that this article requires EU Member States to implement a system of third-party access to distribution systems based on published tariffs.*
- 2. However, this EU Directive is not retained in UK law by the European Union (Withdrawal) Act 2018. This Act retains in UK law only 'direct EU legislation'. Direct EU legislation includes EU Regulations, but will not generally include EU Directives, as EU Directives generally impose requirements which Member States must implement (having a margin of discretion regarding the detail of how they are implemented).*
- 3. Prior to Brexit, it would have been possible to argue that licence drafting which was inconsistent with the EU Directive represented improper implementation by the UK - and as a corollary of that, where more than one interpretation was possible, the licence would have been interpreted on the basis that was consistent with proper implementation. However, following Brexit, the EU Directive is not part of the official hierarchy of UK legislation.*
- 4. I do not therefore fully agree with the consultation response. I'm afraid it doesn't eliminate the issue.*
- 5. Having said that, I do agree with the general sense of what the respondent is saying – the requirements for third party access to licence exempt distribution networks have been implemented in Great Britain under (primarily) Schedule 2ZA of the Electricity Act 1989, and it therefore follows that licensed distributors need a charging methodology that deals (one way or another) with how charges apply in relation with those connected to exempt networks.*

4.130 This issue stems from HV and LV customers which are connected to private networks which are themselves connected at EHV. Those private networks do not necessarily meet the definition of 'Designated Property'. After discussion it was agreed that the intent has always been to treat these customers the same and therefore some wording would need to be added to demonstrate this.

4.131 Previous wording discussed was as follows:

"The CDCM is applicable to "Designated Properties", as defined in Standard Condition 13A (Common Distribution Charging Methodology) of the DNO Party's Distribution Licences and properties connected to Licence Exempt Systems at Low Voltage (LV), Low Voltage substation (LVS) and High Voltage (HV)".

4.132 After discussion, the Working Group agreed to amend the wording as follows:

"The CDCM is applicable to "Designated Properties", as defined in Standard Condition 13A (Common Distribution Charging Methodology) of the DNO Party's Distribution Licences and, if not already catered for, properties connected to Licence Exempt Systems at Low Voltage (LV), Low Voltage substation (LVS) and High Voltage (HV)".

#### Published Data

4.133 One respondent to the consultation raised concerns over whether elements of the solution may result in the disclosure of data not currently in the public domain. The CDCM is based on average data and the only additional information to be included is the percentage of private network customers for each customer type, which does not disclose any sensitive data. For the EDCM only the end tariffs are published, with none of the data used within the models being published by the DNOs. This means that any additional information used by the DNOs to calculate tariffs for EDCM sites under any of the metering arrangements will remain confidential and will not be available in the public domain.

#### Impacted MPANs

##### Shared Metering

4.134 The Supplier would be aware that the site has shared metering as they would be involved in setting up the split of the units/capacity between the sites.

##### Difference Metering

4.135 There would be a metering dispensation in place. It is likely that a Supplier will be aware as sites with difference metering have to appoint the same HHMOA and HHDC as the Registrant of the Boundary Point Metering. There is also a list of sites with a non-confidential site-specific metering dispensation in place available on Elexon's website here [Statement of Site Specific Metering Dispensations - BSC Guidance Notes - Elexon BSC](#), and a mailbox at Elexon for queries relating to metering dispensations - [dispensations@elexon.co.uk](mailto:dispensations@elexon.co.uk).

##### Fully Settled

4.136 It is recognised that fully settled impacted MPANs may be harder to identify initially. Examples of these sites can be high rise flats, office blocks and properties that have been subdivided into flats. Suppliers and DNOs who are unable to identify these impacted MPANs, may require additional information from the PNOs themselves in order to appropriately assign tariffs. Suppliers may be made aware directly by the customer when negotiating the contract or, once they have been initially identified, indirectly via the

Distributor because such customers will be on a specific DUoS tariff and be assigned the LLFC for that tariff.

## 5 Legal Text

### Proposed Legal Text

- 5.1 The DCP 328 Legal Text can be found in Attachment 1 of this Change Report.
- 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 (both boundary and Primary) to:
- Send gross metering data on the non-Settlement MPAN in the same timescale associated with Settlement MPANs; and
  - Embedded Suppliers to allow the boundary Supplier or the Primary Supplier to aggregate their metering data.
- 5.3 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.
- 5.4 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.
- 5.5 Schedule 17 and 18 have been amended to cater for the charging of boundary supplier where difference metering and shared metering occur.
- 5.6 Schedule 17 and 18 have been amended for fully settled arrangement to charge the embedded Suppliers by creating a boundary tariff and allocating the fixed (including a reactive element) and capacity charges included in that boundary tariff to each embedded Supplier based on the proportion of their capacity to that of the boundary capacity.
- 5.7 Schedule 17 and 18 have been amended for residual charges i.e. to charge the boundary supplier and primary supplier where difference metering and Shared metering occurs and to charge each embedded supplier based on their proportion of their capacity to that of the boundary capacity.

### Methodology changes

- 5.8 Changes to the CDCM and EDCM methodologies have been produced (see Attachment 9).

### Consequential changes

- 5.9 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 models are prepared for implementation, should this change be approved.

## 6 Relevant Objectives

### Assessment Against the DCUSA Objectives

6.1 For a DCUSA Change Proposal to be approved it must be demonstrated that it better meets the DCUSA Objectives. There are five General DCUSA Objectives and six Charging Objectives. This change proposal impacts the Charging Objectives.

DCUSA Charging Objectives	Identified impact
<input type="checkbox"/> 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
<input type="checkbox"/> 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
<input type="checkbox"/> 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
<input type="checkbox"/> 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
<input type="checkbox"/> 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
<input type="checkbox"/> 6 that compliance with the Charging Methodologies promotes efficiency in its own implementation and administration.	Negative

6.2 The Working Group believe 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.

6.3 Although the Working Group have identified positive and negative impacts associated with this CP and considering altogether the Working Group believe that overall, this CP better facilitates the DCUSA Charging Objectives.

## 7 Code Specific Matters

### Modelling Specification Documents

7.1 Please see attachment 9.

### Reference Documents

7.2 Not applicable.

## 8 Impacts & Other Considerations

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

8.1 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”.*

8.2 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<sup>14</sup>).

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<sup>14</sup> [DCP388 - Amendments to Facilitate Appropriate Residual Charging for Sites with a Mix of Final and Non-Final Demand](#)

- 8.3 It is also noted that [CMP363 & CMP364<sup>15</sup>: 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.
- 8.4 This change proposal also references existing Balancing & Settlement data items that may change as part of the Market Wide Half-Hourly Settlements (MHHS) SCR. It has been added to the Horizon log of the MHHS Programme.

## Impact assessment

### CDCM Impact Assessment

- 8.5 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 and two thirds HV. The CDCM impact assessment has been revised following the update to remove the HV/LV level from the tariffs and assign these customers to the HV tariff, whereas in the previous version of the models from the second consultation the assumption was that the split should be a third LV, a third HV/LV and a third HV.
- 8.6 In the CDCM impact assessment the original option B solution is referred to as option B1 and the final option B solution, without the HV/LV tariffs, is referred to as option B2.

### Impact on revenue recovered

- 8.7 Option B2 leads to changes in expected revenue recovered from the CDCM.
- 8.8 Option B2 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 B2 and the baseline ranges between +/- 0.015% under the volume assumptions provided by the working group (c. £0.15 million in total across all fourteen DNOs). The size of the remaining mismatch is comparable to or less than already seen in the tariff models due to the rounding of charges to two or three decimal places.

### Comparison between LES and all-the-way bills

- 8.9 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 non-LES customers

- 8.10 Option B2 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 0.17%,

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<sup>15</sup> [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](#)



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

- 8.11 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.
- 8.12 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.
- 8.13 A floor on LES charges was considered by the working group, to ensure that typical LES bills cannot be less than the equivalent LDNO bill, however following discussion with the Authority this was not pursued further. The Working Group recommend however that should there be significant impact on the LDNO network as a consequence of this CP, that they provide such information directly to the Authority as part of their voting response.
- 8.14 The CDCM Impact Assessment can be found in Attachment 9.

#### **EDCM Impact Assessment**

- 8.15 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.
- 8.16 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.
- 8.17 For the solution for fully settled metering, there is a boundary tariff calculated which is then shared between the Suppliers of 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 to Suppliers 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.
- 8.18 A summary of the DCP 328 modelling work can also be found in Attachment 9.

## **9 Implementation Date**

- 9.1 The proposed implementation date for this CP is 01 April 2024. This would potentially mean that the Authority may 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).*

## 10 Voting

10.1 The 328 Change Report was issued to DCUSA Parties for Voting on 10 October 2022.

### Part 1 Matter: Authority Decision is Required

#### Change Solution – Reject

10.2 For the majority of the Party Categories that were eligible to vote, the sum of the Weighted Votes of the Groups in each Party Category which voted to reject the change solution was more than 50%. In accordance with Clause 13.5, the Parties have been deemed to recommend to the Authority that the change solution be rejected.

#### Implementation Date – Reject

10.3 For the majority of the Party Categories that were eligible to vote, the sum of the Weighted Votes of the Groups in each Party Category which voted to reject the implementation date was more than 50%. In accordance with Clause 13.5, the Parties have been deemed to recommend to the Authority that the implementation date be rejected.

The table below sets out the outcome of the votes that were received in respect of the DCP 328 Change Report that was issued on 10 October 2022 for a period of 15 working days.

DCP 328	WEIGHTED VOTING				
	DNO	IDNO	SUPPLIER	CVA REGISTRANT	GAS SUPPLIER
CHANGE SOLUTION	Reject	Reject	Reject	Not Eligible	Not Eligible
IMPLEMENTATION DATE	Reject	Reject	Accept	Not Eligible	Not Eligible

## 11 Recommendations

### DCUSA Parties Recommendation

11.1 DCUSA Parties have voted on DCP 328 and in accordance with Clause 13.5, the Parties have been deemed to recommend to the Authority that the Change Proposal be rejected.

## 12 Attachments

- Attachment 1 - DCP 328 Legal Text
- Attachment 2 – Consolidated Votes
- Attachment 3 – Timeline and Party Obligations from DCP 158



- Attachment 4 – DCP328 Change Proposal Form
- Attachment 5 – DCP328 Issue Responses
- Attachment 6 – Example on how capacity and fixed charges are to be apportioned in the EDCM
- Attachment 7 – DCP 328 First Consultation Document, Responses and Working Group Feedback
- Attachment 8 – DCP 328 Second Consultation Document, Responses and Working Group Feedback
- Attachment 9 – DCP 328 Modelling Documentation