









DCUSA Consultation		At what stage is this document in the process?
<h1>DCP 287</h1> <h2>Generation Credits in the EDCM</h2> <p><i>Raised on the 7 December 2016 as a Standard Change</i></p>		01 – Change Proposal
		02 – Consultation
		03 – Change Report
		04 – Change Declaration
<p>Purpose of Change Proposal:</p> <p>DCP 287 seeks to amend the calculation of credits for embedded generation in the EDCM to take account of potential cost savings for DNOs that can be attributed to embedded generation in the areas of transmission exit charges, direct costs, indirect costs and network rates.</p>		
	<p>The Workgroup recommends that this Change Proposal should proceed to Consultation</p>	
	<p>Parties are invited to consider the questions set in section 10 and submit comments using the form attached as Attachment 1 to dcusa@electralink.co.uk by 27 October 2017.</p>	
	<p>The Working Group will consider the consultation responses and determine the appropriate next steps for the progression of the Change Proposal (CP).</p>	
	<p>Impacted Parties: Distribution Network Operators (DNOs), Distributed Generators and Suppliers</p>	
	<p>Impacted Clauses:</p> <p>Schedule 17 - “EHV Charging Methodology (FCP Model)”;</p> <p>Schedule 18 - “EHV Charging Methodology (LRIC model)”</p>	

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Timetable		
The timetable for the progression of the CP is as follows:		
Change Proposal timetable		
Change Proposal timetable:		
Activity	Date	
Initial Assessment Report Approved by Panel	21 December 2016	
First Consultation issued to Parties	06 October 2017	
First Consultation closes	27 October 2017	
Second Consultation issued to Parties	Late December 2017	
Second Consultation closes	Early January 2018	
Change Report issued to Panel	March 2018	
Change Report issued for Voting	March 2018	
Party Voting Ends	April 2018	
Change Declaration Issued to Authority	April 2018	
Authority Decision	May / June 2018	
Implementation	01 April 2020	

1. Summary

What?

- 1.1 The Distribution Connection and Use of System Agreement (DCUSA) is a multi-party contract between electricity Distributors, electricity Suppliers and large Generators. Parties to the DCUSA can raise Change Proposals (CPs) to amend the Agreement with the consent of other Parties and (where applicable) the Authority.
- 1.2 This CP addresses the issue of whether the calculation of credits for embedded generators in the Extra High Voltage (EHV) Distribution Charging Methodology (EDCM) should include credits for the avoidance of costs on behalf of the Distribution Network Operator (DNO) relating to transmission exit charges, direct costs, indirect costs and network rates.

Why?

- 1.3 The level of credits for embedded generators within the EDCM is determined from the Charge 1 that results from a powerflow analysis of the DNO's network. Although this captures future reinforcement costs, it does not necessarily reflect the full costs savings that can be attributed to embedded generators. More cost reflective credits for generators will place incentives on embedded generators that reflect the benefits they bring to DNOs.

How?

- 1.4 The proposed solution is to apply credits to eligible¹ EDCM embedded generators in the areas of:
 - Transmission exit charges;
 - Direct costs;
 - Indirect costs; and
 - Network rates.

¹Eligible generators are those which have 'proportion eligible for Charge 1 credits' set to 1. The proportion eligible for Charge 1 credits is zero if the F factor that is assigned to the generator is zero and 1 otherwise.

2 Governance

Justification for Part 1 Matter

- 2.1 DCP 287 is considered a Part 1 Matter as it directly affects the level of charges for embedded generators and therefore impacts on competition for embedded generation as specified under clause 9.4.2 (A) of DCUSA, and will indirectly affect (through scaling) the level of charges for demand customers. Therefore, DCP 287 will go to the Authority for determination after the voting process has been completed.

Requested Next Steps

- 2.2 Following a review of the Consultation responses, the Working Group will work to agree the detail of the solution for DCP 287.

3 Why Change?

Background of DCP 287

- 3.1 The principle of this proposal is to amend the credits awarded to EDCM embedded generators to reflect all of the components that result in cost savings to the DNO in a similar way to the methodology used in the Common Distribution Charging Methodology (CDCM), which is used to determine charges for designated High Voltage (HV) and Low Voltage (LV) properties. Each component is listed separately below.

Transmission Exit Charges

- 3.2 The review of embedded benefits undertaken by National Grid in 2013 (charging methodology paper GB ECM-23 [Transmission Arrangements for Embedded Generation](#)) determined a value for the avoided cost of embedded generation on the transmission network. This analysis excluded the cost of transformation located at Grid Supply Points (GSPs), known as supergrid transformers (SGTs). This is because SGTs tend to be fully contributed (i.e. paid for by the DNO) and the cost recovered from the DNO via transmission exit charges.
- 3.3 Under the EDCM, a credit for offsetting transmission exit costs is only paid to qualifying embedded generators that have an agreement with the DNO, the terms of which require the embedded generator, for the purposes of P2/6 compliance, to export power during SGT outage conditions. As most EDCM embedded generators do not have this agreement, very few receive a credit in this respect.
- 3.4 Transmission exit charges recover the capital cost of GSPs, on behalf of transmission companies, from DNOs. Embedded generators may offset demand at the GSP and therefore reduce the need

for future reinforcement at the GSP. Embedded generators may also increase the amount of spare capacity at the GSP which enables more demand to connect without triggering reinforcement. This principle is accepted within the CDCM, where embedded generators receive a credit for offsetting transmission exit charges, but not within the EDCM. In addition, the costs of future reinforcement of GSPs is not included in the locational element of the charge (Charge 1) due to the ownership lying with the transmission company.

Direct Costs

- 3.5 Within the CDCM, designated HV and LV embedded generators receive a credit for reducing direct operating costs at voltage levels above the level of connection. This is because they reduce the demand and therefore the level of infrastructure required at higher voltage levels. This results in less reinforcement and a saving in direct costs.
- 3.6 Annex 1 of schedule 17, s8.3 (d) and schedule 18, s7.4 (d) set out the costs to be included when deriving the future reinforcement costs under the Forward Cost Pricing (FCP) and the Long Run Incremental Cost (LRIC) approaches to load flow modelling respectively, and are as follows:
- (d) The typical unit costs used to derive the cost of reinforcement for a Branch shall:
- (i) reflect the modern equivalent asset value of reinforcing the particular asset;
 - (ii) include overheads directly related to the construction activity;
 - (iii) include building and civil engineering works, in unmade ground.
- 3.7 The costs outlined above therefore do not reflect the savings that result from lower direct costs that are realised by the DNO due to the reduction in size of the infrastructure that needs to be maintained by the DNO. This CP suggests awarding an additional credit to EDCM embedded generators for the avoided direct costs associated with increased infrastructure that may have been required if the embedded generators were not connected to the DNO network.
- 3.8 Within the EDCM an operating intensity of 68% is applied to direct costs for the derivation of demand charges. This operating intensity is used to reflect the apportionment of direct and indirect costs between EDCM and CDCM customers. Effectively, this parameter states that more direct costs (on a relative basis) are spent on the LV and HV network than the EHV network. This CP does not intend to amend this operating intensity which is presented for information only.

Indirect Costs

- 3.9 The CDCM assumes the degree to which indirect costs contribute to demand costs or generation credits on a forward-looking basis via a 60% multiplier within the methodology i.e. 60% is used to represent the proportion of indirect costs which are assumed to vary with demand. There is no equivalent factor applied within the EDCM; demand charges as indirect costs are recovered on a capacity basis rather than a unit basis.
- 3.10 The proposer believes that that some indirect costs vary with the level of demand and are therefore avoidable by the presence of embedded generators. The proposer suggests that this proportion

should be set at 60% to match the proportion in the CDCM. This CP asserts that this variable element of indirect costs (i.e. 60%) should be applied as a credit to EDCM embedded generators using the justification outlined above in 3.9 - that these costs are not contained within Charge 1, but the level of costs are reduced through the presence of embedded generators.

Network Rates

- 3.11 The proposer believes that network rates are another avoidable cost for DNOs. Where fewer assets are required by the DNO the amount of network rates expenditure by the DNO is reduced. As this expenditure is not considered during the derivation of Charge 1 it is therefore not built into the credit assigned to EDCM embedded generators. The proposer therefore believes that the calculation of credits for EDCM embedded generators should be amended to incorporate any savings due to avoided network rates.

Q1 - Do you understand the intent of DCP 287?

Q2 - Are you supportive of the principles of DCP 287? Please provide your rationale

4 Code Specific Matters

Reference Documents

- 4.1 The Working Group agreed that there are no other Working Groups that impact upon the development of DCP 287 however it noted the work being undertaken by DCP 291 "[Application of Generation Credits to EDCM Customers](#)" which is looking into the eligibility criteria for EDCM embedded generators to receive Charge 1 credits.

5 Working Group Assessment

DCP 287 Working Group Assessment

- 5.1 The DCUSA Panel established a Working Group to assess DCP 287. This Working Group consists of DNO, Supplier, consultancy, trade body and Ofgem representatives. Meetings were held in open session and the minutes and papers of each meeting are available on the DCUSA website – www.dcusa.co.uk.
- 5.2 The Working Group discussed why credits are not currently being awarded for the elements considered above within the EDCM. Members considered that credits for CDCM embedded generators are based on the negative of demand charges which means that, by default, the credits for the elements considered above are included. Credits for EDCM generators are based on an incremental approach of powerflow analysis being used and, by default, the elements considered above are not included. The Working Group discussed these points however noted that members

couldn't recall, nor find the reasons as to why credits were not awarded to EDCM embedded generators for the elements considered above at the time of the EDCM's inception. The Working Group would like to understand whether parties can provide any information in this area.

Q3 – Can parties provide any documentation to support why the EDCM does not apply credits for avoided transmission exit charges, direct costs, indirect costs and network rates (apart from transmission exit credits for qualifying generators)?

Application of Credits in EDCM

Transmission Exit Credits

- 5.3 Transmission exit credits are only paid to qualifying EDCM embedded generators that have an agreement with the DNO, the terms of which require the generator, for the purposes of P2/6 compliance, to export power during SGT outage conditions. As most EDCM embedded generators do not have this agreement, very few receive a credit in this respect. Those that do have a capacity-based credit applied to their generation tariff.
- 5.4 The proposal seeks to apply a credit in respect of reduced transmission exit charges which is based on peak time export. The proposed legal text calculates this credit as the reverse of the transmission exit charge for demand customers. However, unlike the demand charge, the legal text proposes to apply this credit on a unit basis (p/kWh) across the super-red time period to EDCM embedded generators which are eligible for Charge 1 credits. This means that EDCM embedded generators which do not export at time of DNO peak (as defined by the super-red time period), or which are deemed not to support the network will not receive a credit for this element.
- 5.5 The Working Group reviewed the proposal to provide credits to EDCM embedded generators for the avoidance of transmission exit charges for DNOs. One issue raised by the Working Group was the application of credits in relation to transmission exit charges for exporting GSPs. It was agreed that this was out of scope, as the current methodologies assume the DNO networks are demand dominant; which does not form part of the intent for this proposal. On this basis, the Working Group agreed that the issue should not be considered further.

Q4 – Do you agree with the principle that EDCM embedded generators should receive a credit for offsetting transmission exit costs? Please justify your rationale.

Q5 - Do you agree that only EDCM embedded generators which are eligible for Charge 1 should receive credits for offsetting transmission exit costs? Please provide your rationale.

Q6 - Do you agree with the Working Group that the issue regarding exporting GSPs is out of scope? Please provide your rationale.

Direct Costs, Indirect costs and network rates

5.6 This CP proposes to apply the additional credit elements for the avoided reinforcements as identified and valued under the powerflow model (LRIC or FCP). During the Working Group discussions, an alternative approach of using network use factors (NUFs) was also considered.

Option 1 – Amend Calculation of Unit Rates Based on Charge 1

5.7 Within the EDCM a powerflow model is used to determine a locational charge for demand sites. Two powerflow modelling approaches are in use by DNOs: the LRIC approach and the FCP approach. The locational charge to demand is referred to as Charge 1 and is further split into the:

- 'network charge' (FCP) or 'local charge' (LRIC) relating to the voltage of connection; and
- 'parent charge' and 'grandparent charge' (FCP) or 'remote charge' (LRIC) relating to voltage levels above but not including the voltage of connection.

5.8 Charge 1 is the basis for the unit rate credit that is awarded to eligible EDCM embedded generators. It is awarded as a credit during the super-red time period to provide an incentive for the generator to export at this time. The super-red time period represents the time period where the DNO would benefit most from the generator exporting. It is important that the price signal during this time period reflects the costs avoided by the DNO to ensure generation plant is utilised in an efficient manner. For these reasons, option 1 proposes to apply a credit to the super-red unit rates in preference to a capacity credit.

5.9 Charge 1 reflects the likelihood of additional future reinforcement costs based on an increment of demand together with an underlying growth assumption. Consequently, when the network used by a demand customer is close to fully utilised, an increment of demand by that customer is more likely to drive reinforcement in the near future, so Charge 1 is high. Conversely, if there is spare capacity on the network used by a demand customer, an increment of demand by that customer has little impact, and so Charge 1 is low.

5.10 Charge 1 is a charge that is derived for EDCM demand, and forms the basis of a credit for eligible EDCM embedded generators, with eligibility determined from the ability of the embedded generator to provide network support.

5.11 The formula used under the LRIC approach for determining credits for embedded generators which are eligible for credits and which have not opted out of Use of System charges is set down in DCUSA (Schedule 18, 6.5), simplified as follows:

$$£/\text{kW SR Export Rate} = (\text{Local Charge 1} + \text{Remote Charge 1})$$

5.12 The formula used under the FCP approach for determining credits for embedded generators which are eligible for credits and which have not opted out of Use of System charges is set down in DCUSA (schedule 17, 6.3), simplified as follows:

$$\text{£/kW SR Export Rate} = (\text{Network Charge 1} + \text{Parent Charge 1} + \text{Grandparent Charge 1})$$

5.13 The proposed methodology to implement this change is to scale up the existing credit (as derived using the formula above) by multiplying it by the following elements:

- 1 + DOCR
- 1 + INCR*0.6
- 1 + NRCR

Where:

- DOCR = Direct operating costs contribution rate (per cent)
- INCR = Indirect costs contribution rate (per cent)
- NRCR = Network rates contribution rate (per cent)

5.14 The indirect costs contribution rate is reduced by applying a factor of 0.6. This reflects the factor used in the CDCM to reflect the proportion of indirect costs that are deemed to vary with demand. This factor is applied in the CDCM in recognition that some indirect costs vary with demand, but some are fixed and unlikely to change if demand increases or decreases. An equivalent factor is not contained within the EDCM demand charge because the cost is recovered via a capacity charge rather than a unit based charge.

5.15 The proposal to inflate the existing credit in this way means that those EDCM embedded generators that currently receive a large credit (and therefore are most beneficial to the network) will receive an increase in the credit received. Conversely, those EDCM embedded generators which do not currently receive a credit will not start to receive a credit as a result of this calculation.

Option 2 – Network Use Factors

5.16 An alternative approach put forward by the proposer and discussed by the Working Group is to apply the additional credit element based on the assets that the site is deemed to use as identified using the NUFs.

5.17 The difference between these approaches is that the increased credit awarded for avoided reinforcement costs under option 1 will vary from site to site based on the congestion level of the network, and therefore how close the network is to requiring reinforcement. Under option 1, where Charge 1 is zero, no additional credit would be applied through the adjustment for direct costs, indirect costs and network rates (although a credit for avoided transmission exit charges would still

apply). Where Charge 1 is large (i.e. the network is close to reinforcement) applying additional elements would make the credit larger.

- 5.18 Under Option 2, the NUFs are used to determine how much of the existing network a site is deemed to use and the additional credits are based on these assets. This would result in additional credits for eligible EDCM embedded generators regardless of the level of network congestion.
- 5.19 It was noted that this option would benefit all eligible EDCM embedded generators, irrespective of whether they have the potential to reduce the DNO asset base.

Q7 – Do you agree with the principle that credits should be awarded to eligible EDCM embedded generators for avoided costs associated with direct costs, indirect costs and network rates? Please provide your rationale against each.

Q8 – Which of the two options do you support?

Option 1 – amending the calculation of credits based on the level of Charge 1; or

Option 2 – amending the calculation of credits based on the NUFs for the site.

Please provide your rationale.

Working Group Analysis

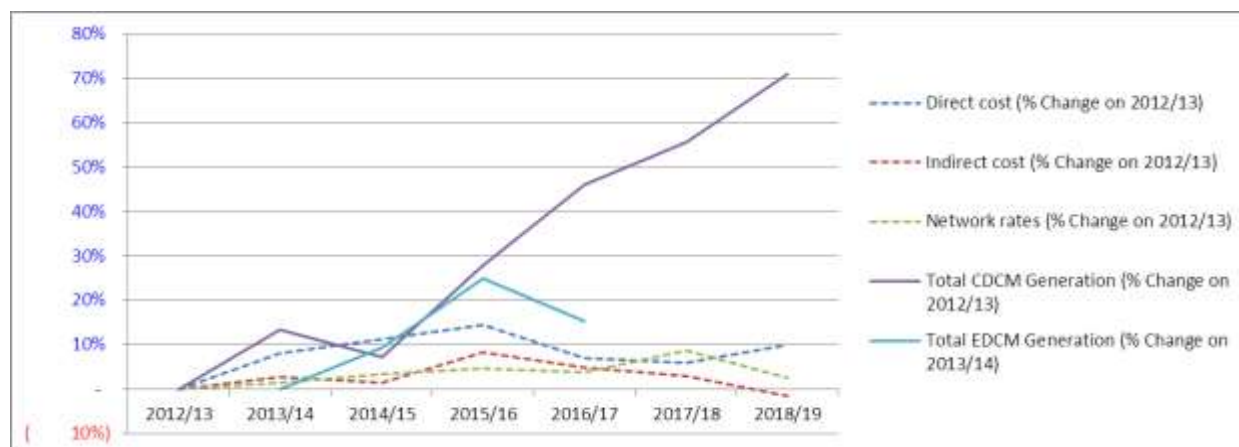
- 5.20 The Working Group considered what impact an increase in embedded generation over recent years has had on the level of direct/indirect costs and network rates. On the network rates, they have not seen a correlation between lower demand levels and lower network rates. The Working Group discussed if embedded generation was to exactly match demand would indirect costs actually go down by 60%. It was agreed to undertake analysis on the increase in embedded generation on the network and its impact on direct, indirect and network costs.
- 5.21 The Working Group considered that it would be beneficial to compare the change in costs against the change in demand and to include that analysis in the consultation. The Working Group agreed that gross demand volumes from the CDCM can be used.

Analysis of CDCM direct costs, indirect costs and network rates inputs. The costs have been indexed back to 2012/13 prices (using inflation forecasts as used for 2018/19 charge setting where necessary), and these have been plotted against CDCM generation forecasts and EDCM generation actuals.

Direct/indirect costs and Network Rates	Direct cost (£m/year)	Indirect cost (£m/year)	Network rates (£m/year)	Direct cost (% Change on 2012/13)	Indirect cost (% Change on 2012/13)	Network rates (% Change on 2012/13)
2012/13	335	1,255	334			
2013/14	362	1,289	339	8%	3%	2%
2014/15	373	1,274	346	11%	2%	4%
2015/16	384	1,359	350	15%	8%	5%
2016/17	358	1,317	347	7%	5%	4%
2017/18	355	1,294	363	6%	3%	9%
2018/19	368	1,235	343	10%	(2%)	3%

CDCM Generation	LV and LV Sub Generation (GWh)	HV Generation (GWh)	Total CDCM Generation (GWh)	CDCM Generation (% Change on 2012/13)
2012/13	276	6,842	7,118	
2013/14	431	7,650	8,081	14%
2014/15	346	7,283	7,629	7%
2015/16	586	8,524	9,110	28%
2016/17	809	9,591	10,400	46%
2017/18	891	10,190	11,081	56%
2018/19	1,092	11,073	12,165	71%

EDCM Generation	Total EDCM Generation (eligible for credit) (GWh)	Total EDCM Generation (not eligible for credit) (GWh)	Total EDCM Generation (GWh)	EDCM Generation (% Change on 2013/14)
2012/13				
2013/14	11,521	17,014	28,535	
2014/15	12,332	18,868	31,200	9%
2015/16	11,326	24,305	35,630	25%
2016/17	10,991	21,947	32,938	15%
2017/18				
2018/19				



- 5.22 One Working Group member noted their view is that the volume of embedded generation provided in the analysis could be misleading due to wind and solar generation connections not leading to increased network security. It was noted that the analysis provided shows 43TWh of total embedded generation which is quite a small proportion of total demand.
- 5.23 One member highlighted that savings would not be expected straight away but into the future, noting it could take a few years for the potential benefits of embedded generation to be seen. Another member suggested consideration should be given to how much the costs would be if the current embedded generation wasn't there and suggested that the increase in costs may be steeper in this scenario.
- 5.24 The Working Group considered the extent to which these costs vary with demand. It was thought that if the costs don't vary with demand then embedded generation won't impact these costs. Alternatively, if the costs do vary with demand then embedded generation may have an impact on these costs. One member of the Working Group suggested that the number of customers may be a stronger driver of cost than energy flow for some costs. The member suggested that elements of the indirect costs (e.g. call centre costs) could be being driven by customer numbers and this should be looked at in more detail. It was also noted that elements such as employee pensions will remain as a constant cost element that will vary with staffing levels rather than demand. It was concluded that it is possible that correlation between demand and cost is a secondary effect resulting from the historic correlation between demand energy flows and customer numbers and consequent required staffing levels, and therefore generation energy flows that offset demand energy flows (and so disrupt the historic correlation between demand energy flows and customer numbers) would not impact costs as the generation energy flows would not impact the underlying cost driver.

Q9 - Do you think there is a direct relationship between energy flows and indirect costs, direct costs and network rates incurred by a DNO, or do you think the nature of the relationship is more complex such that the reduction of demand flows caused by embedded generators may not reduce the costs incurred? Please provide your rationale.

- 5.25 The proposer is suggesting that when applying a credit to EDCM embedded generation for offsetting indirect costs, a 60% factor should be applied. This factor represents the amount of indirects that are deemed to vary with the level of demand. The proposer has used the value in the CDCM where it is set at 60% as per the rationale set out in clauses 5.14 and 5.15 of this consultation document.

Q10 – Do you agree that the 60% value (as used in the CDCM) should be used to determine the proportion of indirect costs which EDCM embedded generators have the potential to offset?

- 5.26 The Proposer noted that specific examples could be used to strengthen the principle that the credits for EDCM embedded generators don't take into account the additional cost savings attributable to

them instead of looking at the macro level analysis. It was also noted that this means analysis at the micro level would need to be undertaken as there is potentially significant 'noise' at the macro level (i.e. other factors influencing costs, and so masking any actual correlation between the activity of embedded generators and DNO costs). The Working Group agreed that analysis at a more micro level including specific examples should be provided in the consultation alongside analysis on the proportions of indirect costs that are believed to vary with demand. A paper summarising this analysis is provided as Attachment 3.

5.27 The micro level analysis identifies the benefit of avoided reinforcement that can occur from the presence of an embedded generator in two ways. Firstly, the DNO may avoid the need to install new assets when connecting a new customer as the embedded generator can provide network security if it complies with the design policies of the DNO. Secondly, the embedded generator could reduce peak demand if it were to export at the appropriate time which reduces the infrastructure required upstream of that asset. The paper provides an example from the Common Connection Charging Methodology which shows the reinforcement that could be saved in a specific example relating to connecting a new housing estate with a 2MW capacity requirement.

5.28 The paper highlights that although the benefit of the reduced reinforcement costs is reflected in the powerflow methodology adopted by the DNO within the EDCM, there is no allowance for the additional cost savings associated with this avoided reinforcement. In the housing estate example, the DNO can avoid the need to build 1.3km of 11kV network by relying on the embedded generator. However, the DNO will also avoid the ongoing costs associated with this network as follows:

- Direct ongoing costs associated with this asset (e.g. inspection and maintenance costs, operating expenditure relating to fault repairs, the cost of tree cutting etc.).
- Closely associated indirect costs that relate to the work that has been avoided (e.g. network design and engineering, project management, engineering management and clerical support, wayleaves, stores etc.).
- Network rates are based on the value of a DNO's assets. In this example, the avoidance of building the cable and other assets saves the DNO the network rates associated with these assets.

Network Rates

5.29 The Working Group notes that the Charge 1 figure within the EDCM has no direct correlation/counterpart in CDCM but considers that the 500MW model is the closest mechanism which factors the cost of investing in the network on a unit basis. At present, Charge 1 is used to derive the credit for eligible EDCM embedded generators and no element of network rates is reflected in the credit. This is a different approach to the CDCM where the credit for embedded generators includes an element for reduced DNO network rates.

5.30 The Proposer suggests that embedded generators can potentially reduce the level of network rates that a DNO pays. This is because network rates are primarily based on the assets owned by the

DNO. Consequently, if the presence of embedded generators reduces the amount of network assets that a DNO owns, it will reduce the network rates bill.

5.31 The Working Group has reviewed how network rates are determined by the Valuation Office, in order to establish whether a link exists between network rates and DNO assets and the extent to which this is a direct link.

5.32 A DNO's 'rateable value' is calculated periodically by the ratings valuation agency, based on the theoretical rental value of the DNO's properties. The valuation is calculated on a basis known as the receipts and expenditure method. The receipts and expenditure method has regard to the revenue that a hypothetical tenant could expect to generate by conducting business at the hereditament. The hypothetical tenant's likely expenditure and a return on capital employed are then deducted. The residual amount is the rent (i.e. rateable value) the hypothetical tenant should pay.

5.33 In simple terms, this approach calculates a DNO's rateable value as:

$$\text{Rateable Value} = (\text{Gross Receipts} - \text{Operating Costs}) \times (1 - \text{Tenant's Share})$$

5.34 Gross receipts (i.e. Use of System revenues) are reasonably certain for any given five-year period (assuming the calculation is carried out at the start of a price control period) and so can be forecast in nominal prices for the five year period in question.

5.35 Operating costs are forecast based on evidence of historic costs, and both Ofgem and DNO forecasts made at the start of each price control. An adjustment is also made for depreciation on Regulatory Asset Value (RAV) to reflect the fact that the hypothetical tenant is required to invest in assets to be used within the hereditament.

5.36 The 'Tenant's Share' refers to the DNO shareholder's return. The Tenant's Share is calculated on the basis of what the hypothetical tenant would reasonably take out of the business to make it worth their while taking the tenancy.

5.37 If the presence of an embedded generator were to lead to reduced assets on the DNO network (e.g. the need for fewer upper voltage substations), the DNO's RAV would decrease, with a consequent decrease in revenue. Taken in isolation this would give a theoretical decrease to the rateable value. However, the reduced asset base could also lead to lower operating costs, with an offsetting effect on the rateable value. Further details of this can be found at: [Valuation office - Section 371: electricity distribution networks](#).

5.38 It should be noted that not all of the DNO's assets are considered rateable. For example, the buildings and structures at substations are rateable, whilst the transformers themselves are not (on the basis that the hypothetical tenant would rent the substation itself, but would then be required to invest in the assets to be used within it, in the same way that an office building is rateable but the computer equipment used within it is not). Underground cables and overhead lines are considered rateable on the basis that the DNO effectively owns the ground in which the cables sit.

Q11 – Do you believe that embedded generators have the ability to reduce a DNO's overall network rates bill? Please provide your rationale.

Other Considerations

- 5.39 The Working Group discussed their thoughts on if now is the right time for this CP to be progressed through the DCUSA change process. The Proposer outlined that the CP is a self-contained change and does not believe it should be put on hold until a point in time when a more fundamental change is due to occur. One member noted their view is that this is not the best time as the CDCM/EDCM Review Group is likely to cover the same detail and propose changes that may alter any work completed as part of DCP 287. The Proposer noted that the work carried out during the DCP 287 Working Group could feed into the analysis that the CDCM/EDCM Review Group carries out.
- 5.40 The CDCM/EDCM review has looked at five areas, with the recently submitted report covering progress to date on each:
- a. Type of Costing Model;
 - b. Tariff Structures;
 - c. Licenced Distribution Network Operator Charging Arrangements;
 - d. New Products (e.g. Storage); and
 - e. Combining the CDCM and EDCM Methodologies.
- 5.41 In parallel with this review, Ofgem issued a consultation on a 'Targeted Charging Review' (TCR) and launched a Significant Code Review (SCR) on the 4th August 2017.
- 5.42 Alongside launching the SCR Ofgem announced that it is setting up a Charging Futures Forum (CFF), previously known as the Charging Coordination Group. The CFF will provide some guidance on how to progress the CDCM/EDCM review with work potentially recommencing later in 2017.
- 5.43 One of the recommendations, while the CFF is being established, is that work will continue on the costing model and tariff options to develop a template/prototype by September and then await direction from the CFF.
- 5.44 The SCR, whilst establishing the CFF, is also looking at residual charges, which does not impact this CP. It is therefore suggested that unless directed otherwise by the Authority that this CP should continue to be developed.

6 Solution and Legal Text

- 6.1 The legal text will be developed based on the responses to this consultation.

7 Relevant Objectives

Assessment Against the DCUSA Objectives

7.1 The Proposer considers that the following DCUSA Objectives are better facilitated by DCP 287.

Impact of the Change Proposal on the Relevant Objectives:	
Relevant Objective	Identified impact
Charging Objective Two - 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
Charging Objective Three - 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

7.2 The proposer believes that this CP better meets charging objective two as the tariffs for EDCM embedded generators will be more cost reflective and therefore result in a more efficient dispatch of plant and the siting of plant within the distribution network. Both of these will result in the promotion of effective competition in generation.

7.3 The proposer believes that this CP better meets charging objective three as it increases the cost reflectivity of tariffs within the EDCM by awarding credits to eligible embedded generators that more closely reflect the benefits they bring to DNOs and thereby encourages the development of efficient, co-ordinated and economical distribution networks.

Q12 – Do you believe that this change proposal better facilitates the DCUSA Charging Objectives? Please provide your rationale against each objective.

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 Ofgem launched a SCR on the 4th August 2017 on the TCR. One aspect of this is looking into residual charges, which the Working Group believes does not impact this CP (with Parties' views sought at

question 12). It is therefore suggested that unless directed otherwise by the Authority that this CP should continue to be developed.

Consumer Impacts

8.2 The Working Group noted that higher credits would result in higher demand charges; however the impact of this has yet to be quantified. This will be undertaken as part of the review of the consultation responses and the further development of this CP.

Environmental Impacts

8.3 In accordance with DCUSA Clause 11.14.6, the Working Group assessed whether there would be a material impact on greenhouse gas emissions if DCP 287 were implemented. The Working Group did not identify any material impact on greenhouse gas emissions from the implementation of this CP.

Engagement with the Authority

8.4 Ofgem has been fully engaged throughout the development of DCP 287 as an Observing member of the Working Group.

9 Implementation

9.1 The proposed implementation date for DCP 287 is 01 April 2020.

10 Consultation Questions

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

Number	Questions
1	Do you understand the intent of DCP 287? Please provide your rationale
2	Are you supportive of the principles of DCP 287? Please provide your rationale
3	Can parties provide any documentation to support why the EDCM does not apply credits (apart from transmission exit credits for qualifying generators)?
4	Do you agree with the principle that EDCM embedded generators should receive a credit for offsetting transmission exit costs? Please justify your rationale.
5	Do you agree that only EDCM embedded generators which are eligible for Charge 1 should receive credits for offsetting transmission exit costs? Please provide your rationale.

6	Do you agree with the Working Group that the issue regarding exporting GSPs is out of scope? Please provide your rationale.
7	Do you agree with the principle that that credits should be awarded to eligible EDCM embedded generators for avoided costs associated with direct costs, indirect costs and network rates? Please provide your rationale against each.
8	Which of the two options do you support? Option 1 – amending the calculation for Charge 1 or Option 2 – NUF? Please provide your rationale.
9	Do you think there is a direct relationship between energy flows and indirect costs, direct costs and network rates incurred by a DNO, or do you think the nature of the relationship is more complex such that the reduction of demand flows caused by embedded generators may not reduce the costs incurred? Please provide your rationale.
10	Do you agree that the 60% value (as used in the CDCM) should be used to determine the proportion of indirect costs which EDCM embedded generators have the potential to offset?
11	Do you believe that embedded generators have the ability to reduce a DNO's overall network rates bill? Please provide your rationale.
12	Do you believe that this change proposal better facilitates the DCUSA Charging Objectives? Please provide your rationale against each objective.

10.2 Responses should be submitted using Attachment 1 to dcusa@electralink.co.uk no later than, **27 October 2017**.

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

Attachments

- Attachment 1 – Response Form
- Attachment 2 – DCP 287 Change Proposal
- Attachment 3 – DCP 287 – Examples of EDCM Benefits