

DCUSA Change Declaration		At what stage is this document in the process?
<h1 data-bbox="124 353 550 448">DCP 313</h1> <h2 data-bbox="124 504 890 649">Eligibility Criteria for EDCM Generation Credits</h2> <p data-bbox="124 683 842 728"><i>Raised on 10 October 2017 as a Standard Change</i></p>		<p data-bbox="1189 347 1348 414">01 – Change Proposal</p> <p data-bbox="1189 470 1412 504">02 – Consultation</p> <p data-bbox="1189 560 1348 627">03 – Change Report</p> <p data-bbox="1189 672 1348 739">04 – Change Declaration</p>
<p data-bbox="119 817 566 862">Purpose of Change Proposal:</p> <p data-bbox="119 884 1364 974">DCP 313 seeks to improve transparency of the eligibility criteria for EDCM generators to receive super red credits, and to improve consistency in the application thereof.</p>		
	<p data-bbox="239 1052 1428 1176">DCUSA Parties have voted on DCUSA Change Proposal (DCP) 313 with the outcome being a recommendation to the Authority on whether the Change Proposal (CP) should be accepted or rejected.</p> <p data-bbox="239 1232 1236 1265">The DCUSA Parties consolidated votes are provided as Attachment 1.</p>	
	<p data-bbox="239 1299 1436 1377">For DCP 313, DCUSA Parties have voted and recommended to the Authority to determine that:</p> <ul data-bbox="295 1400 1204 1500" style="list-style-type: none"> • the proposed variation (solution) should be accepted; and • the implementation date should be accepted 	
	<p data-bbox="239 1534 1276 1624">Impacted Parties: Distribution Network Operators (DNOs), Independent Distribution Network Operators (IDNOs), Generators and Suppliers</p>	
	<p data-bbox="239 1657 518 1691">Impacted Clauses:</p> <p data-bbox="239 1713 1109 1803">Schedule 17 – EHV Charging Methodology (FCP Model); and Schedule 18 – EHV Charging Methodology (LRIC Model).</p>	

Contents		 Any questions?																				
1	Summary	3																				
2	Governance	4																				
3	Why Change?	4																				
4	Solution	7																				
5	Relevant Objectives	21																				
6	Impacts & Other Considerations	24																				
7	Implementation	26																				
8	Legal Text	26																				
9	Code Specific Matters	26																				
10	Voting	27																				
11	Recommendations	27																				
12	Attachments	28																				
Timeline		 0207 432 3011																				
<p>The timetable for the progression of the CP is as follows:</p> <p>Change Proposal timetable</p> <table border="1"> <thead> <tr> <th>Activity</th> <th>Date</th> </tr> </thead> <tbody> <tr> <td>Initial Assessment Report Approved by Panel</td> <td>11 October 2017</td> </tr> <tr> <td>First Consultation issued to Parties</td> <td>23 February 2018</td> </tr> <tr> <td>Second Consultation issued to Parties</td> <td>07 December 2018</td> </tr> <tr> <td>Change Report issued to Panel</td> <td>13 March 2019</td> </tr> <tr> <td>Change Report issued for Voting</td> <td>22 March 2019</td> </tr> <tr> <td>Party Voting Ends</td> <td>12 April 2019</td> </tr> <tr> <td>Change Declaration issued to Authority</td> <td>16 April 2019</td> </tr> <tr> <td>Authority Decision</td> <td>24 May 2019</td> </tr> <tr> <td>Implementation Date</td> <td>01 April 2021</td> </tr> </tbody> </table>		Activity	Date	Initial Assessment Report Approved by Panel	11 October 2017	First Consultation issued to Parties	23 February 2018	Second Consultation issued to Parties	07 December 2018	Change Report issued to Panel	13 March 2019	Change Report issued for Voting	22 March 2019	Party Voting Ends	12 April 2019	Change Declaration issued to Authority	16 April 2019	Authority Decision	24 May 2019	Implementation Date	01 April 2021	 DCUSA@electralink.co.uk
Activity	Date																					
Initial Assessment Report Approved by Panel	11 October 2017																					
First Consultation issued to Parties	23 February 2018																					
Second Consultation issued to Parties	07 December 2018																					
Change Report issued to Panel	13 March 2019																					
Change Report issued for Voting	22 March 2019																					
Party Voting Ends	12 April 2019																					
Change Declaration issued to Authority	16 April 2019																					
Authority Decision	24 May 2019																					
Implementation Date	01 April 2021																					
		Proposer: Andrew Enzor																				
		 Andrew.Enzor@northernpowergrid.com																				
		 07834 618994																				

1 Summary

What?

- 1.1 The Distribution Connection and Use of System Agreement (DCUSA) is a multi-party contract between electricity Distributors and 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 The DCUSA currently requires Distribution Network Operators (DNOs) to determine an F Factor for each Extra High Voltage (EHV) Distribution Charging Methodology (EDCM) embedded generator based on the criteria set down in Engineering Recommendation P2/6 – ‘Security of Supply’ (ER P2/6) and Engineering Technical Report 130 – ‘Application Guide for Assessing the Capacity of Networks Containing Distribution Generation’ (ETR130). The F Factor is determined based on a site-specific assessment of the contribution to network security of each EDCM embedded generator, taking into account availability and the operating regime, alongside intermittency.
- 1.3 EDCM embedded generators are deemed to be eligible to receive charge one credits (unit rate credits applicable in the DNO’s peak ‘super-red- period, calculated based on a power flow analysis of the DNO’s network) if they have a non-zero F Factor, and are deemed not eligible to receive charge one credits if they have a zero F Factor.
- 1.4 This CP seeks to improve the transparency around the determination of the eligibility of EDCM embedded generators to receive charge one credits.

Why?

- 1.5 This CP has been raised following a concern raised by embedded generators that there is a lack of transparency and potential lack of commonality in the method by which DNOs determine the F Factor, and consequently whether prospective sites will be eligible for charge one credits.

How?

- 1.6 The proposed solution will require DNOs to populate the ‘proportion eligible for charge one credits’ field based on technology type rather than on F Factor, i.e. set to one for all non-intermittent EDCM embedded generators and according to the status quo for all intermittent EDCM embedded generators (i.e. set to one if a non-zero F Factor has been assigned and set to zero otherwise).
- 1.7 The ‘proportion eligible for charge one credits’ field for mixed sites will be based on the non-intermittent generation installed capacity as a percentage of the Maximum Export Capacity.
- 1.8 This would result in the process for determining generation credits being non-binary and should provide the industry with a more future-proofed solution.
 - EDCM embedded generators with only intermittent generation technology installed:

- If the DNO has determined the site does not support the network in line with ETR130 (and so has zero F Factor under the status quo) the site will remain ineligible for charge one credits;
- If the DNO has determined the site does support the network in line with ETR130 (and so has non-zero F Factor under the status quo) the site will remain eligible for charge one credits.
- EDCM embedded generators with only non-intermittent generation technology installed:
 - If the DNO has determined the site does not support the network in line with ETR130 (and so has zero F Factor under the status quo) the site will become eligible for charge one credits where currently it is not;
 - If the DNO has determined the site does support the network in line with ETR130 (and so has non-zero F Factor under the status quo) the site will remain eligible for charge one credits.
- EDCM embedded generators with the combination of intermittent and non-intermittent generation technology installed:
 - If the DNO has determined the site does not support the network in line with ETR130 (and has zero F Factor under the status quo) the site will become partially eligible for charge one credits where currently it is not;
 - If the DNO has determined the site does support the network in line with ETR130 (and so has non-zero F Factor under the status quo) the site will become partially eligible for credits where currently it is fully eligible.

2 Governance

Justification for Part 1 Matter

2.1 DCP 313 is classified as a Part 1 Matter as it will potentially have impacts on both 9.4.1 and 9.4.2 of DCUSA:

- 9.4.1 – it is likely to have a significant impact on the interests of electricity consumers; and
- 9.4.2 – it is likely to have a significant impact on competition in distribution.

3 Why Change?

Background of DCP 313

3.1 The CP (Attachment 3) was raised by Northern Powergrid and seeks to address a Distribution Charging Methodology Forum (DCMF) Methodologies Issues Group (MIG) issue raised in

November 2016 which identified potential differences in the application of generation credits to EDCM embedded generators across different DNOs.

- 3.2 The concern raised by embedded generators was that there is a lack of transparency and potential lack of commonality in the method by which DNOs determine the F Factor, and consequently whether perspective sites will be eligible for charge one credits.
- 3.3 DCP 291 – ‘Application of Generation Credits to EDCM Customers’¹ was raised to resolve this issue, by making all EDCM embedded generators eligible for charge one credits regardless of the F Factor assigned. The DCP 291 Working Group subsequently agreed that this was not the best available solution to the issues raised, which led to the withdrawal of DCP 291 and the creation of this CP.
- 3.4 There were originally two proposed solutions for this change, both of which would improve the transparency around the eligibility for charge one credits, with the second solution also achieving a transparent approach for the assignment of F Factors to EDCM embedded generators.

Original Proposal Option 1 – Proportion eligible for credits set according to technology type rather than based on the F Factor assigned for non-intermittent generators.

- 3.5 This option would require an amendment to Schedules 17 and 18 to require DNOs to set the ‘proportion eligible for charge one credits’ field to one for all non-intermittent generators and according to the status quo for intermittent generators (i.e. set to one if a non-zero F Factor has been assigned and set to zero otherwise). This would lead to:
 - All intermittent EDCM embedded generators remaining unchanged;
 - Non-intermittent EDCM embedded generators which the DNO has determined do not support the network in line with ETR130 (which have zero F Factor) being eligible for charge one credits where currently they are not; and
 - Non-intermittent EDCM embedded generators which the DNO has determined do support the network in line with ETR130 (which have non-zero F Factor) remaining eligible for charge one credits.
- 3.6 The proposer stated that this would provide greater transparency to non-intermittent EDCM embedded generators of the process by which the DNO will determine eligibility for charge one credits, and so enable them to more easily predict the likely charges/credits they will face when deciding where to site plant.
- 3.7 The proposer considered that this option would improve transparency in the eligibility for credits by divorcing the eligibility criteria for non-intermittent EDCM embedded generators from the site-specific assessment carried out to determine the F Factor. The assignment of the F Factor would remain unchanged by this option, and so a non-intermittent EDCM embedded generator could still be assigned a zero F Factor if they were deemed by the DNO to not support the network.

¹ [DCP 291](#)

3.8 As a result, there would be a possibility that a non-intermittent EDCM embedded generator which was deemed not to support the network would be awarded credits. This would be unlikely, as a generator which does not support the network is likely to be in an area of low demand, and hence charge one credits is likely to be zero. Nonetheless, it is possible that charge one would be non-zero, and so a generator which does not offset reinforcement costs could be awarded credits under this solution.

Original Proposal Option 2 – F Factor assigned based on technology type with no site-specific assessment.

3.9 This option would require an amendment to Schedule 17 and 18 to no longer reference ER P2/6 when assigning the F Factor, but rather to include a modified table 2-1 from ER P2/6 in the EDCM, and so set the F Factor based only on technology type with no site-specific assessment. This would lead to:

- Intermittent EDCM embedded generators which have zero F Factor remaining unchanged (this would be the majority of intermittent generators);
- Intermittent EDCM embedded generators with a non-zero F Factor being assigned a zero F Factor and so becoming ineligible for charge one credits (this would be the minority of intermittent generators);
- Non-intermittent EDCM embedded generators which the DNO has determined do not support the network in line with ETR130 (which have zero F Factor) being reassigned a non-zero F Factor and so becoming eligible for charge one credits; and
- Non-intermittent EDCM embedded generators which the DNO has determined do support the network in line with ETR130 (which have non-zero F Factor) being assigned the same F Factor and so remaining eligible for charge one credits.

3.10 The proposer stated that this would provide greater transparency to all EDCM embedded generators (compared to option one which provides greater transparency for non-intermittent EDCM embedded generators only) of the process by which the DNO would determine eligibility for charge one credits, and so enable them to more easily predict the likely charges/credits they would face when deciding where to site plant. This option would also improve transparency in the determination of the F Factor.

3.11 The possibility identified in option one that a generator which is deemed not to support the network would be awarded credits remained a risk under option two. As with option one, this would be unlikely, as a generator which does not support the network is likely to be in an area of low demand, and hence charge one is likely to be zero. Nonetheless, it is possible that charge one would be non-zero, and so a generator which does not offset reinforcement costs could be awarded credits under this option.

3.12 The risk identified under option one of a scenario where a non-intermittent EDCM embedded generator would be awarded higher credits if it were deemed not to support the network by the DNO than if it were deemed to support the network by the DNO did not exist under this option. This

is because both generators would be assigned the same F Factor based on table 2-1 from ER P2/6, and so both would have the same charge one calculated.

4 Solution

DCP 313 Working Group Assessment

- 4.1 The DCUSA Panel established a Working Group to assess DCP 313. This Working Group consisted of DNO and Supplier representatives and an Ofgem observer. Meetings were held in open session and the minutes and papers of each meeting are available on the DCUSA website – www.dcusa.co.uk.
- 4.2 EDCM embedded generators are deemed to be eligible to receive charge one credits (unit rate credits applicable in the DNO's peak 'super-red' period, calculated based on a power flow analysis of the DNO's network) if they have a non-zero F Factor, and are deemed not eligible to receive charge one credits if they have a zero F Factor.
- 4.3 The load flow element of the EDCM uses a maximum demand scenario and minimum demand scenario to determine the likelihood of the need to reinforce the assets to which a customer is connected, and how that likelihood changes with an increment in demand at each node. The F Factor is used to determine the output of each generator in the maximum demand scenario – the generators export capability is multiplied by the F Factor to determine its output in the maximum demand scenario. Where the generation is not controllable, it cannot be relied upon to output at the time of peak demand and so is assigned an F Factor of zero and will be assumed to have no generation output in the maximum demand scenario. Conversely, where a generator is controllable, it can be relied upon to be active at the time of peak, and so is assigned a non-zero F Factor and is assumed to be generating in the maximum demand scenario.
- 4.4 If there is a high level of generation in the maximum demand scenario (i.e. if there are multiple generators with non-zero F Factor at a given Grid Supply Point (GSP)), it is likely that some demand on higher voltage assets will be offset by that generation, and so the likelihood of needing to reinforce will be lower and hence charge one lower for customers which use those assets.
- 4.5 Ofgem published a letter in 2012² which was focussed on intermittent and non-intermittent generation and whether the generators should receive credits. Its determination at the time was that it did not want demand customers paying for both credits and network reinforcement. Below is an extract from the Ofgem document:

“...it would be inappropriate to implement the DNOs' proposal at this time, because it could leave to demand customers paying for both partial credits and for network

² <https://www.ofgem.gov.uk/ofgem-publications/43878/edcm-export-decision-letter-16nov12-final-pdf>

reinforcements. Therefore, as part of this decision, we are placing a condition on our approval of the proposed EDCM for export, namely that super-red credits must not be paid to intermittent generators.

However, the DNOs' proposal approach could be appropriate in future, if there was no risk of demand customers paying both for credits and for reinforcements. We expect that this would require any proposal to be compatible with the relevant planning standards."

- 4.6 The Working Group discussed whether this CP would be in conflict with this decision. It was agreed that the CP is seeking to provide improved transparency in this area without impacting the fundamentals of the EDCM that will still comply with the Ofgem decision.
- 4.7 The Working Group discussed an alternative approach of providing the information at the offer stage so that generators were aware at the time whether they would benefit from a credit in their tariff should they decide to proceed with the connection. Whilst this is a sensible approach it was felt that this can be done now by DNOs, but it is outside the scope of this CP.
- 4.8 The Working Group discussed both original options.

Option 1 – Proportion eligible for credits set according to technology type rather than based on the F Factor assigned for non-intermittent generators.

- 4.9 Option 1 is a straightforward proposal to allow credits to be awarded for all non-intermittent generators regardless of the F Factor assigned, whilst maintaining the status quo for intermittent generators (i.e. those with non-zero F Factor (a minority) being eligible for credits and those with zero F Factor (the majority) being ineligible for credits).
- 4.10 It was agreed by the Working Group that there is a risk of paying credits to some generators who have been deemed not to support the network (and so demand customers would be funding both the credit to that generator and any reinforcement required over which that generator has had no influence), but this is likely to be low and the credit minimal.
- 4.11 This option partially divorces the EDCM from ER P2/6 in that the site-specific assessment carried out for non-intermittent EDCM embedded generators when assigning the F Factor would not be taken into account when determining whether to provide a credit. The impact is limited to non-intermittent generators that currently have a zero F Factor. To counter this, there is a benefit of simplicity and transparency.

Option 2 – F Factor assigned based on technology type with no site-specific assessment

- 4.12 Option 2 completely divorces the EDCM from ER P2/6. However, this option is incorporating into the EDCM the table within ER P2/6 which details the F Factor values to assign and adding to it to cater for a default value for technology not recognised within the table including future new technologies. As a consequence, it was agreed by the Working Group to change the reference

from an F Factor to a Peak Generation Demand Factor (PGD Factor) to avoid having different definitions of F Factor in ER P2/6 and the EDCM.

- 4.13 It was recognised by the Working Group that, should a new technology be developed that was deemed to be worth of a non-zero F Factor, it is likely that a further CP would be required, but the introduction of a default value would result in more cost reflective charges being applied in the interim period between the first connection of such a technology and the implementation of a CP.
- 4.14 The following table describes the impact of both options on EDCM embedded generators, grouped by technology type and the F Factor which has been assigned under the status quo:

Generator Type	Impact on Option One	Impact on Option Two
1 – Intermittent with zero F Factor (the majority of intermittent EDCM generators)	No impact – these generators are currently not eligible for credits and will remain not eligible for credits	No impact – the PDG Factor assigned to these customers will align with the F Factor currently assigned (zero) and so these generators will remain not eligible for credits
2 – Intermittent with non-zero F Factor (a minority of intermittent EDCM generators)	No impact – these generators are currently eligible for credits and will remain eligible for credits	All impacted – the PDG Factor assigned to these customers will be zero and so will not align to the F Factor currently assigned. These generators are currently eligible for credits and will become not eligible for credits
3 – Non-intermittent with zero F Factor (i.e. those which the DNO has determined do not support the network; a minority of the non-intermittent EDCM generators).	Potential for some impact – these generators are currently not eligible for credits. It is likely that charge one will be zero (or negative, in which case it is ‘capped’ at zero) for these customers (on the basis that they do not support the network and so are likely to be in an area of low demand and/or high generation), and if this is the case, despite becoming eligible for credit, the actual credit awarded will be	Potential for some impact – the PDG Factor assigned to these generators will be non-zero and so will not align with the F Factor currently assigned. These generators are currently not eligible for credits and will become eligible for credits. It is likely that charge one will be zero (or negative, in which case it is ‘capped’ at zero) for these customers (on the basis that they do not support the network and so are likely to be

	zero.	in an area of low demand and/or high generation), and if this is the case, despite becoming eligible for credits, the actual credit awarded will be zero.
4 – Non-intermittent with non-zero F Factor (the majority of non-intermittent EDCM generators).	No impact – these generators are currently eligible for credits and will remain eligible for credits	Possible slight impact – the non-zero PDG Factor assigned to these generators will align with the non-zero F Factor currently assigned, and so the change from F Factor to PDG Factor will not directly impact the inputs to the power flow model for these customers but will impact the inputs for others (specifically those described in rows two and three) and hence the level of generation assumed in the peak demand scenario will be slightly different and consequently charge one may vary. Given the small number of generators directly impacted by the move from F Factor to PDG Factor, this impact is expected to be small.
5 – Demand customers	No impact	The change from F Factor to PDG Factor will impact the inputs to the power flow model for some generators (specifically those described in rows two and three) and hence the level of generation assumed in the peak demand scenario will be slightly different and consequently charge one may vary. Given the small number of generators

		<p>directly impacted by the move from F Factor to PDG Factor, this impact is expected to be small.</p>
--	--	--

DCP 313 First Consultation

- 4.15 To aid further development of the solution for this CP, the Working Group issued a consultation to Parties on 23 February 2018. The aim of the first consultation was to ask the industry for views on the principles of the change and which original solution they preferred. There were eight respondents to the first consultation comprising of five DNOs, two Generators and one Supplier. A copy of the first consultation and Working Group conclusions can be found as Attachment 4.
- 4.16 The majority of respondents agreed that they understood and agreed with the principles and intent of the change. However, one DNO respondent voiced that they did not agree or support the change. The Working Group discussed the DNO's response and decided that the Party's interpretation of the change differed from that of the Working Group. This is addressed in paragraph 4.24 below.
- 4.17 Respondents to the consultation also noted that the legal text did not refer to how tariffs should be determined when there is a single generation connectee which combines intermittent and non-intermittent generation technology. The Working Group agreed that this was a valid concern, which is addressed below in paragraph 4.26.
- 4.18 One respondent noted that some DNOs are referring to ETR130 and ERP P2/6 more widely to determine the proportion eligible for generation credits. They stated that some DNOs will say that unless the network relies on Distributed Generation (DG) to meet the standard laid down in ER P2/6 that the credits should be set to zero by setting the F Factor to zero. This means that even when Table 2-1 states a non-zero F Factor, the DNO will set the F Factor to zero as it has concluded that the network does not rely on DG. So even if charge 1 is non-zero the generation credits are set to zero as the 'proportion eligible for charge one credits' will be zero. In the view of the respondent, this results in the prevention of cost reflective generation credits being signalled to generators and makes it impossible for potential DG to calculate the potential generation credits.
- 4.19 Other responses to the consultation highlighted that inclusion of a table that includes specific technology types would not be sufficient as it would not future-proof potential new technologies with a default value for "Other Technologies" available within Option 2 not guaranteeing a level playing field between the listed technologies and those that are not explicitly included in the table.
- 4.20 One Party did not support the introduction of discrimination based on technology type into the EDCM. In their view, technology type is not a driver of network requirements and therefore does not drive costs. For consistency of application the Party favoured the introduction of a forum where F Factor calculations could be discussed amongst peers, and where best practice could be agreed

and shared. This group could be a special meeting of the Distribution Charging Methodologies Development Group, perhaps on an annual basis, with the invite extended to network representatives familiar with the F Factor calculations for their network areas/ whilst there was support in the Working Group for such an initiative it was suggested that this could be progressed outside of this change.

- 4.21 One Party stated that within Option 2 it is not necessary to assess the underlying characteristics of the controllable generator as the total revenue available to the generator will be the operating hours multiplied by the credit rate. A generation technology which is either less reliable or unable to maintain its maximum output will receive a lower credit by virtue of its lower output over the peak. However, if contributing at peak the units which it generates are as equivalent to those generated by any other plant.
- 4.22 The majority of respondents supported Option 1, with Parties citing that Option 1 is clearer and easier for customers and Suppliers to understand as it is unambiguous, where Option 2 is more complex for Parties to understand the arrangement which would apply to them. Option 2 also received a degree of support. The Working Group by a majority supported the progression of Option 1 in preference to Option 2; however, accepted that Option 1 still needed further development to cover mixed sites, and that Option 2 should also be further refined.

Working Group Conclusions and next steps

- 4.23 The Working Group identified that there were a number of areas of further work having discussed the Parties' responses to the first consultation:
- The intent of the Change Proposal;
 - Refine the solution to cater for mixed sites; and
 - Consider whether any alternative solutions are required.

Intent of the CP

- 4.24 The Working Group discussed the intent of the CP and agreed that it could be interpreted in one of two ways – being either to improve transparency by simply adding additional text to clarify the existing requirements, or to improve transparency by amending the requirements themselves. The Proposer confirmed that the latter had been the aim when drafting the CP, and hence the Working Group agreed to seek Panel approval to amend the intent “...*amend the eligibility criteria for EDCM generators to receive super red credits, and to improve transparency and consistency in the application thereof.*”

4.25 A paper³ was submitted to the DCUSA Panel meeting in April 2018. The Panel, whilst recognising the concern raised by one Party, were comfortable with the original intent and as such it was sufficient when trying to amend the eligibility criteria for EDCM generation credits. The paper was therefore rejected and the original intent states:

“The intent of this Change Proposal is to improve transparency of the eligibility criteria for EDCM generators to receive super red credits, and to improve consistency in the application thereof.”

Mixed Sites

4.26 The Working Group discussed the issue of mixed sites. It was noted by the Working Group that this issue is unambiguously resolved for Low Voltage (LV) and High Voltage (HV) connections within the DNO’s Licence Condition 14 statements whereby the dominant technology determines whether the site is intermittent and non-intermittent. A similar clause could be added to Option 1 to cover Extra High Voltage (EHV) mixed sites, providing greater transparency in this area.

4.27 An alternative approach (later labelled as Option 1A) was suggested that looked at whether the solution should be non-binary and that the ‘proportion eligible for charge 1 credits’ should be based on the installed capacity of the non-intermittent as a percentage of the Maximum Export Capacity.

4.28 It was also noted by the Working Group that this may help future proof the CP as DNOs are increasingly seeing connection applications for the co-location of battery storage plant (currently treated as non-intermittent generation in the EDCM – see DNO guidance note⁴) with intermittent generating plant.

Request for Information

4.29 The Working Group agreed to undertake a Request for Information (RFI) to determine the number of mixed sites currently connected and what process DNOs undertake to determine the F Factor.

4.30 The Working Group asked for information of the following:

1. How many sites currently have intermittent and non-intermittent generation on the same site;
2. What is the DNO process under the EDCM in determining credits for intermittent and non-intermittent generators at the same site;

³ [DCUSA Open Session Panel Paper \(Panel 2018_0418_06\)](#)

⁴

http://www.energynetworks.org/assets/files/electricity/futures/Distribution%20Guidance%20Note%20for%20Storage_Final.docx

3. Would the F Factor be reduced on a mixed site resulting in a reduction in the credit provided and if so, is there a similar reduction in the credit provided, e.g. if the F Factor was reduced by 50% would it reduce the credit by 50% too; and
4. On sites where there is intermittent and non-intermittent generation and each technology type is fed by a separate MPAN would the DNOs provide a credit associated with each MPAN or would credit be associated with the site.

4.31 The Working Group reviewed the RFI responses from five of the six DNOs and noted that there are currently only four mixed sites, three of which are actually charges separately so do not meet the Working Group's definition of a mixed site. RFI responses are in Attachment 6.

4.32 In response to question two on how the calculation of the F Factor would be made, the majority referred to ER P2/6 and ETR130 together with a site-specific assessment. One response went further indicating that they would assess the site and use an average of the generic F Factors based on the proportion of intermittent and non-intermittent generating plant on the site. It was clarified at a Working Group meeting that this response specifically referred to new connections.

4.33 There was a mixed response to the question as to whether the F Factor would be reduced on a mixed site resulting in a reduction in the credit provided and whether such a reduction would result in a similar reduction in the credits provided. The expectation was that the F Factor would be reduced by the credit would be subject to the outcome of the load flow analysis. The Working Group agreed that the reduction is not likely to be linear.

4.34 On the final question as to whether mixed generation sites having separate MPANs would provide a credit associated with each MPAN or with the site, the response again was mixed. Of the respondents, only one DNO had instances where this would be applicable, and they currently charge each MPAN separately. Of those that currently do not have mixed sites, one DNO indicated that they would provide a credit based on the site rather than on each MPAN. Others indicated that it would depend on the connection agreement and the number of connection points stating that in some instances it would be by MPAN and in others by site. As a consequence of this, this CP is catering for mixed sites in order to cover both instances.

Alternative Options

4.35 The Working Group sought additional information from a consultation respondent who felt that DNOs are non-compliant with the DCUSA and the Charging Methodologies, as suggested in their response to question three of the first DCP 313 consultation.

4.36 The response was:

“Some DNO's are referring to ETR130 and P2/6 more widely to determine whether to zero the proportion eligible for generation credits. Engineering recommendations P2/6 is a guidance document on a system planning and network capacity requirements and details the minimum standard for the security of supply of a network. Where a network does not meet the requirements

of P2/6 without the contribution of DG the DNO may use the value in Table 2-4 to determine how much of the DG's capacity can be taken into account in assessing the adequacy of the network.

Certain DNO's are using this to say that unless the network relies on DG to meet the standard laid down in P2/6 that the generation credits should be set to zero by setting the F Factor to zero. This means that even when Table 2-4 states a non-zero F Factor and the Charge 1 is non-zero (indicating future demand led reinforcement) the generation credits are set as the F Factor is overridden and set to zero.

It is our view that this is an incorrect application of the requirements of Schedule 17 of DCUSA and results in the prevention of cost reflective generation credits being signalled to generators. It also makes it impossible for potential DG to calculate the potential generation credits as they rely, in certain DNO regions, on a subjective assessment and application of the F Factor."

- 4.37 The Working Group discussed that this respondent believes that F Factors should be assigned based on characteristics of the generating plant without taking into account whether or not the generator actually makes a contribution to security of supply, i.e. without considering the location of the generator and the demand on the area of network to which it is connected. This would be achieved by the insertion of Table 2-4 from ER P2/6 into DCUSA (Option 2) as this would result in the F Factor being set entirely based on the generation technology without considering its location.
- 4.38 However, other consultation respondents expressed concern that the hard-coding of values from ER P2/6 into DCUSA would create a situation where a DCUSA change was needed each time a new generation technology connects to a DNO network. Whilst the Working Group sought to alleviate this in Option 2 by including default values for new technologies which could be used until such a change were progressed, respondents highlighted that these 'default' values are arbitrary and do not necessarily reflect the merits of new generation technology for network support.
- 4.39 There was a further concern that developments to ER P2/6 (most notably the transition from ER P2/6 to P2/7 (if approved by the Authority) which would remove the differences between intermittent and non-intermittent generation) would mean that further CPs would be needed to maintain alignment, where the current approach of referencing ER P2/6 does not require such CPs.
- 4.40 It was suggested that an alternative third option (labelled Option 2B) should be developed to strengthen the legal text in an attempt to ensure that F Factors are assigned without taking into account the location of the generator whilst also continuing the reference ER P2/6 and so not suffer from the defect identified in paragraphs 4.38 and 4.39 above.
- 4.41 The Working Group agreed that they development of Option 2B warranted a further consultation to be issued to Parties as the legal text would be completely different to the first consultation. One Working Group member highlighted that the majority of respondents to the first consultation were supportive of Option 1 and the new option could change industry views and therefore a consultation needed to be issued.

DCP 313 Second Consultation

4.42 The Working Group issued its second consultation to industry on 07 December 2018. A copy of the second consultation and the Working Group conclusions can be found as Attachment 4. The aim of the second consultation was to ask the industry for views on the newly developed Options 1, 1A and 2B and to distinguish whether there would be any detrimental impacts if any of the approached were implemented. Details of each solution can be found below.

Option 1

4.43 This solution will require DNOs to populate the 'proportion eligible for charge one credits' field based on technology type rather than on F Factor, i.e. set to one for all non-intermittent EDCM embedded generators and according to the status quo for all intermittent EDCM embedded generators (i.e. set to one if a non-zero F Factor has been assigned and set to zero otherwise). Mixed sites will be classed as non-intermittent if the installed capacity of the non-intermittent generation is greater than or equal to 50% of the Maximum Export Capacity.

4.44 The implementation of Option 1 would lead to the following outcomes for four groups of EDCM generators:

- EDCM embedded generators with only intermittent generation technology installed:
 - No change, i.e. eligible for credits if a non-zero F Factor has been assigned and ineligible otherwise;
- EDCM embedded generators with only non-intermittent generation technology installed:
 - If the DNO has determined the site does not support the network in line with ETR130 (and so has a zero F Factor under the status quo) the site will become eligible for charge one credits where currently it is not;
 - If the DNO has determined the site does support the network in line with ETR130 (and so has a non-zero F Factor under the status quo) the site will remain eligible for charge one credits.
- EDCM embedded generators with a combination of intermittent and non-intermittent generation technology installed, where the installed capacity of non-intermittent generation technology is less than 50% of the Maximum Export Capacity:
 - If the DNO has determined the site does not support the network in line with ETR130 (and so has a zero F Factory under the status quo) the site will remain ineligible for charge one credits;
 - If the DNO has determined the site does support the network in line with ETR130 (and so has a non-zero F Factor under the status quo) the site will remain eligible for charge one credits.
- EDCM embedded generators with a combination of intermittent and non-intermittent generation technology installed, where the installed capacity of non-intermittent generation technology is greater than or equal to 50% of the Maximum Export Capacity:

- If the DNO has determined the site does not support the network in line with ETR130 (and so has a zero F Factor under the status quo) the site will become eligible for charge one credits where currently it is not;
- If the DNO has determined that site does support the network in line with ETR130 (and so has a non-zero F Factor under the status quo) the site will remain eligible for credits.

Option 1A

4.45 This solution will require DNOs to populate the 'proportion eligible for charge one credits' field based on the non-intermittent generation installed capacity as a percentage of the Maximum Export Capacity.

4.46 This would result in the process for determining generation credits being non-binary and should provide the industry with a more future-proofed solution.

- EDCM embedded generators with only intermittent generation technology installed:
 - If the DNO has determined the site does not support the network in line with ETR130 (and so has zero F Factor under the status quo) the site will remain ineligible for charge one credits;
 - If the DNO has determined the site does support the network in line with ETR130 (and so has non-zero F Factor under the status quo) the site will remain eligible for charge one credits.
- EDCM embedded generators with only non-intermittent generation technology installed:
 - If the DNO has determined the site does not support the network in line with ETR130 (and so has zero F Factor under the status quo) the site will become eligible for charge one credits where currently it is not;
 - If the DNO has determined the site does support the network in line with ETR130 (and so has non-zero F Factor under the status quo) the site will remain eligible for charge one credits.
- EDCM embedded generators with the combination of intermittent and non-intermittent generation technology installed:
 - If the DNO has determined the site does not support the network in line with ETR130 (and has zero F Factor under the status quo) the site will become partially eligible for charge one credits where currently it is not;
 - If the DNO has determined the site does support the network in line with ETR130 (and so has non-zero F Factor under the status quo) the site will become partially eligible for credits where currently it is fully eligible.

The table below summarises the eligibility criteria for Option 1 and Option 1A in tabular format

Site	Has the DNO determined that the site supports the network in line with ETR130 and P2/6	Eligibility under status quo	Eligibility under DCP 313 Option 1	Eligibility under DCP 313 Option 1A
EDCM embedded generators with only intermittent generation technology	Yes	Eligible	Eligible	Eligible
	No	Ineligible	Ineligible	Ineligible
EDCM embedded generators with only non-intermittent generation technology	Yes	Eligible	Eligible	Eligible
	No	Ineligible	Eligible	Eligible
EDCM embedded generators with a combination of intermittent and non-intermittent generation technology	Yes	Eligible	<50% non-intermittent: Eligible =>50% non-intermittent: Eligible	Partly Eligible
	No	Ineligible	<50% non-intermittent: Ineligible =>50% non-intermittent: Eligible	Partly Eligible

Option 2B

- 4.47 Option 2B would involve clarifying the use of F Factors in the power flow modelling to explicitly require that the DNO should determine whether the generator is sufficiently reliable to provide a contribution to security of supply should the need arise, not whether the generator is currently making a contribution. This would involve assigning the F Factor in line with the process laid out in ER P2/6 and ETR130 without considering the location of the generator.
- 4.48 This solution aims to strengthen the legal text without including table 2-1 from ER P2/6.
- 4.49 To ensure that the impact of implementing this option was fully understood, the Working Group instructed TNEI to conduct qualitative assessment on the power flow model of the EDCM to determine the impact that this change would have on the current generator credits. Results of this impact assessment can be found in Sections 6.3-6.12 below and the TNEI report can be found as Attachment 7.

Advantages and disadvantages of the options

Option 1 and Option 1A

- 4.50 Option 1 and Option 1A both have the advantage of simplicity. They represent a relatively minor change from the status quo, with no changes to any of the inputs used for power flow modelling and a straightforward change to the 'proportion for eligible charge one credits'. These options ensure commonality in the proportion eligible for charge 1 credits but not for the assignment of F Factors.
- 4.51 Option 1 has the advantage of additional simplicity over Option 1A in that the 'proportion eligible for charge one credits' input would remain binary (i.e. zero or one), but this simplicity comes at the expense of creating a 'cliff-edge'. Under Option 1 a mixed site where the non-intermittent installed

capacity as a proportion of Maximum Export Capacity is 49% would be entirely ineligible for credit but where the proportion is 50% the site would be entirely eligible for credit. Under Option 1A this would be smoothed by the former having 49% eligible for credit and the latter 50% eligible for credit.

- 4.52 Option 1 and Option 1A both do not resolve the interpretation of ER P/26 and ETR130 requirements for assigning F Factors, and so any lack of commonality which exists in the power flow modelling approach under the current arrangements will continue to exist under the new arrangements if either option is implemented.
- 4.53 A Working Group member suggested, in their view, that there is also a risk under Option 1 and Option 1A that a scenario where a non-intermittent EDCM embedded generator would be awarded higher credits if it were deemed not to support the network by the DNO than if it were deemed to support the by the DNO. This is because in the case where the generator is deemed to support the network, it will have a non-zero F Factor, and so will be assumed to be generating at the time of peak demand (in line with the load flow methodology), and so the time to reinforcement on the local network will be longer and charge one lower. If the same generator were deemed not to support the network, it would be assigned a zero F Factor, and so assumed to not be generating at the time of peak demand (in line with the load flow methodology), and so the time to reinforcement on the network will be shorter and the charge one higher. Under this option, the generator in both scenarios would be eligible for charge one credits (because it is non-intermittent) but charge one would be higher in the case where the generator is deemed not to support the network, and so the credits the generator received would be higher in this scenario.

Option 2B

- 4.54 Option 2B would allow DNO licensees to have a common approach in determining the F Factor to apply for a given generator. EDCM embedded generators would be able to understand in advance the likely range of F Factor which could be assigned to a prospective connection, and so whether it is likely to be eligible for credit or not. Although this option might help ensuring commonality in the interpretation of the interaction of the EDCM and ER P2/6, this Option relies on Table 2-1 in the ER P2/6 which lists only a limited number of technologies and relies on constant updates to reflect the technological advancement. Improved cost reflectivity would in this case lead to loss of simplicity and transparency.

Clarification for Demand Dominated Sites

- 4.55 Whilst developing the solutions for this CP, the Working Group identified a further area where greater clarity would be desirable, relating to the treatment of EDCM sites with non-zero Maximum Export Capacity but which are treated as 'demand dominated'.
- 4.56 For the purposes of load flow modelling each site is treated as either a demand or generation connectee (not both), based on whether its dominant operating mode is that of a demand site or a generation site. This is basically determined by whether the maximum import capacity or maximum export capacity is higher, or whether the kWh demand or kWh generation over a given period is higher.
- 4.57 F Factors are assigned to generation sites for the purpose of determining their output in the 'maximum demand scenario', considered in the load flow modelling. F Factors are not assigned to demand dominated sites as they only relate to generation.

- 4.58 In the existing legal text, the proportion eligible for charge one credits is determined based on the 'F Factor that is assigned to the Connectee'. For demand dominated sites, no F Factor has been assigned so it is not clear what value the proportion eligible for charge 1 credits should take.
- 4.59 The Working Group have resolved this in the proposed legal text for each option by defining the proportion eligible for charge one credits separately for generation dominated sites (based on the F Factor which has been assigned) and for demand dominated sites with on-site generation (based on the F Factor which would have been assigned had the site been treated as generation dominant).

Working Group Conclusions

- 4.60 There were eight respondents to the second consultation which comprised of five DNOs, one Supplier and two generation companies. A copy of all the consultation responses and Working Group comments and conclusions can be found as attachment 4.

Q1: Do you believe that this CP should specifically cater for mixed sites? Please provide your rationale.

- 4.61 The Working Group concluded that there was support from industry to include mixed sites as part of this CP, however, there were some concerns that this may need to be revisited in the future when the number of mixed sites start to increase. Further information on this can be found in section 4.64 below in response to question 2.

Q2: Are there any further implications of mixed sites on the solutions of this DCP which the Working Group have not addressed? Please provide your rationale.

- 4.62 The Working Group noted that there was nothing further that should be considered at this time, however, once again noted that there have been examples raised for further work to be done in the future when more mixed sites are connected to the network and industry can collect more data.

Q3: Which solution do you support and why?

- 4.63 The Working Group concluded that the majority of respondents indicated support for Option 1A to be progressed. The Working Group, except the Proposer, agreed that Option 1A should be taken forward to the Change Report stage. The Proposer of the CP subsequently decided that they would not be raising an alternate CP to be voted on by industry.

Q4: Do you agree with the proposed solution for demand dominated sites? If not, please provide your rationale.

- 4.64 The Working Group concluded that all respondents to question four of the second consultation agreed with the proposed solution for demand dominated sites.

Q5: Do you have any comments on all options of the proposed legal text?

4.65 The Working Group noted all responses to this question and agreed that they would re-review the legal text for Option 1A and consider all suggested amendments in their finalisation. More information on the finalised legal text can be found in section 8 below.

Q6: Which of the DCUSA Charging Objectives does this CP better facilitate? Please provide your supporting comments.

4.66 The Working Group noted all the responses to this question and highlighted that the Working Group view is included in Section 5 below.

Q7: Are you aware of any wider industry development that may impact upon or be impacted by this CP?

4.67 The Working Group noted all responses to this question and agreed that although DCP 313 may have interaction with the ongoing Access and Forward-Looking Charging Significant Code Review (SCR), the CP should continue to progress to completion as the solution could be applied for several years before any changes are implemented on conclusion of the SCR.

Q8: The proposed implementation date for DCP 313 is 01 April 2021. Do you agree with the proposed implementation date?

4.68 The Working Group concluded that the majority of respondents were supportive of a 01 April 2021 implementation date for this CP. More information regarding the implementation can be found in section 7 below.

Working Group Next Steps

4.69 Following a review of the consultation responses, the Working Group agreed to progress with Option 1A which includes a solution for mixed sites and demand dominated areas.

4.70 However, the Working Group noted that this may need further review in the future if there were an increase in the number of mixed sites that are connected to the network.

4.71 The Working Group reviewed the minor legal text amendments suggested by Northern Powergrid in response to the second consultation and agreed with the amendments relating to Option 1A. Further information on the legal text can be found in section 8 below.

5 Relevant Objectives

Assessment Against the DCUSA Objectives

5.1 For a DCUSA CP to be approved it must be demonstrated that it better meets the DCUSA Objectives. There are five DCUSA General Objectives and six DCUSA Charging Objectives. This CP impacts the DCUSA Charging Objectives.

5.2 The Working Group unanimously considers that when reviewing the DCUSA Charging Objectives as a whole, they would be better facilitated by the implementation of DCP 313. Rationale for their decisions can be found below.

Impact of the Change Proposal on the Relevant Charging Objectives:	
Relevant Objective	Identified impacts and rationale
Charging Objective One – 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	Neutral
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	Slightly Negative
Charging Objective Four – that, so far as is consistent with Clauses 3.2.1 to 3.2.1, the Charging Methodologies, so far as is reasonably practicable, properly take account of developments in each DNO Party's Distribution Business	Positive
Charging Objective Five - that compliance by each DNO Party with the Charging Methodologies facilitates compliance with the Regulation on Cross-Border Exchanges in Electricity and any relevant legally binding decisions of the European Commission and/or the Agency for the Co-operation of Energy Regulator	Neutral
Charging Objective Six - that compliance with the Charging Methodologies promotes efficiency in its own implementation and administration.	Positive

Charging Objective Two

5.3 The Working Group unanimously consider that this Objective is positively facilitated by DCP 313 because the CP provides better transparency and so enables generators to better predict the likely charges that they will face.

Charging Objective Three

5.4 Under the status quo the proportion eligible for charge one credits used in the EDCM model is directly linked to the inputs to the power flow model (i.e. based on the F Factor used). This CP would remove this link. The impact analysis which the Working Group has been able to carry out shows that the change has an impact on charge for generators connected to only one DNO's networks, suggesting that the disconnect created between power flow modelling and the EDCM is material only for one DNO.

5.5 Several Working Group members and consultation responses argue that the CP would have a positive impact on this Objective. Those respondents questioned the validity of the assumptions which the impacted DNO currently uses when assigning F Factors (see paragraph 6.12 and 6.13), and so argue that the cost-reflectivity of charges for that DNO is improved, with minimal impact on charges for other DNOs. It was also generally recognised by the Working Group that it is extremely unlikely that a non-intermittent generator would receive higher credits if they were deemed not to support the network than if they were classified to support the network (a risk noted in paragraph 3.8).

5.6 However, the majority of the Working Group also agreed that the CP would have a slightly negative impact on this objective. This is because of:

- The separation which would be created between the principles used for charge setting and the engineering standards that DNOs are required to follow; and
- The disconnect which would be created between the inputs used for power flow modelling (i.e. the F Factor) and those used in the EDCM itself (i.e. the 'proportion eligible for charge one credits').

Charging Objective Four

5.7 The majority of the Working Group also considered that this Objective would be positively facilitated by this CP because the change would support network operators to meet the developments in their businesses. In their role as proactive parties on using and dispatching flexibility services, Distribution System Operators would benefit from a clear and standard approach when determining the eligible technologies.

Charging Objective Six

5.8 Finally, the Working Group unanimously consider that this Objective would be positively facilitated but his CP because a harmonised approach in defining the eligibility criteria across the DNO areas will guarantee a more efficient implementation of the generation credits.

6 Impacts & Other Considerations

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

- 6.1 Having considered the views from some respondents to both the consultation documents, the Working Group agreed that although there could be cross-over with the current Access and Forward-Looking Charging SCR, the solution for this CP should still be progressed since the benefit of the change would be available for several years before any changes made on the conclusion of the SCR process can be implemented.
- 6.2 As the Working Group have decided to continue with Option 1A of the proposed solution, there will need to be a further CP raised to reference the change from ER P2/6 to ER P2/7 should P2/7 be approved by the Authority. This will be to rectify the reference to ER P2/6 in the legal text. The Working Group noted that the decision on this work is with the Authority for their determination (at the time of writing this Change Declaration) and the DCUSA Secretariat is aware that there are further references in DCUSA to ER P2/6 in addition to this CP if the ER P2/7 work is accepted.

Consumer Impacts

- 6.3 Consultants TNEI were instructed to conduct analysis on all three scenarios and provide a report to the Working Group detailing the impact on consumers when changing a generation F Factor in the powerflow modelling. A copy of the full impact assessment report can be found as attachment 6.

Overall Impact

- 6.4 A qualitative assessment has been made of the impact changing an embedded generator F Factor may have on customer charge 1 values and network use factors (NUFs). If the F Factor of a generator is defined based purely on technology type then generators which were deemed not to contribute to network security and were assigned a zero F Factor could be assigned a non-zero F Factor. This would have a similar effect as if these generators were added as new generation into the maximum demand scenario model.
- 6.5 In general, adding a new generator may delay the year in which network branches could require reinforcement. Delaying the year of reinforcement would generally reduce customer charge 1 values in both LRIC and FCP methodologies.
- 6.6 The amount of any charge reduction would depend on the location of branches, whose reinforcement has been delayed, with respect to customers. For LRIC, this depends on the branches which a nodal demand 'uses', while for FCP it depends on the network group which the nodal demand is in.
- 6.7 In addition to the relative locations of nodal demand, branches and generators, the cost reduction will be influenced by the branch reinforcement cost and reinforcement year. Delaying reinforcement of a more expensive branch or a branch which requires reinforcement in 'early' years will have the greatest impact on costs.

- 6.8 It is possible that adding new generators will have no impact on customers charges. This happens in FCP if the new generators are not large enough to delay branch reinforcement or there are no branches with delayed reinforcement are not “used” by the customer.
- 6.9 New generation is more likely to reduce charge 1 values in a demand dominant network than in a generation dominant network.
- 6.10 Adding a new generator does not change the branches ‘used’ by a nodal demand when calculating NUFs. In demand dominant networks the new generator may decrease the maximum contingency flow on those branches which a nodal demand uses, which may generally decrease NUFs. There is a case, however, where the maximum contingency flow on a demand dominant branch may be increased by the addition of a new generator, which would increase NUFs.
- 6.11 In a generation dominant network adding a new generator may increase the maximum contingency flow on branches used by a nodal demand, which may increase NUFs. The base flow on branches used by the nodal demand, however, may either increase or decrease depending on branch/load/generator locations which would either decrease or increase NUF values correspondingly.
- 6.12 When a new generator alters the maximum contingency flow of a branch the magnitude by which the NUF factor is altered would depend on the size of the change in flow in proportion to the branch rating. Whether a branch NUF allocation increases or decreases in a generation dominated asset would further depend on the magnitude of this change combined with the magnitude of change in ‘base flow’ compared to ‘base flow load’. If the change in flow values is small compared to the branch rating (and existing base flow) then the magnitude change to NUF values will also be small.
- 6.13 The Working Group conducted a request for information (RFI) from DNOs to determine the impacts on EDCM tariffs for Option 1 and Option 2 during the first consultation. The outcome of the RFI can be found in attachment 5.
- 6.14 The majority of DNO areas provided impacts on their EDCM tariffs for option one and the impact assessment showed that for the majority of DNO areas, there would be no impact on EDCM tariffs if option one was accepted. However, one DNO areas highlighted that there would be an impact on customers in their area.
- 6.15 It was noted that in this area, 33 generators would be affected by the changes of option one, which would mean a difference of between 0.501p/kWh and 10.425p/kWh on the super-red unit rate export tariffs for the generators affected.
- 6.16 Impact assessments could not be completed on Option 2 by all DNOs as there would have been financial impacts to do so. The DNOs who were able to complete the impact assessment concluded that there would be no impacts on their EDCM tariffs if Option 2 were accepted.
- 6.17 The consultation period provided the DNOs who were unable to complete the impact assessment the opportunity to carry out the impact assessment if they wished to do so.
- 6.18 Please note that the Working Group have taken forward Option 1A which includes the variant for mixed sites. The impact assessment is no different to the assessment conducted on Option 1 as there were no mixed sties identified.

Environmental Impacts

6.19 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 313 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

6.20 Ofgem has been fully engaged throughout the development of DCP 313 as an observer on the Working Group.

7 Implementation

7.1 The proposed implementation date for DCP 313 is 01 April 2021.

7.2 DCP 313 is classified as a Part 1 Matter and therefore Authority determination is required.

8 Legal Text

8.1 The DCP 313 proposed legal text acts as Attachment 2 to this Change Declaration.

8.2 The legal text involves a simple change to the current legal text to make all non-intermittent EDCM embedded generators eligible for charge one credits, regardless of the F Factor assigned. However, for cases where there are mixed generation sites the proportion eligible for charge 1 credits is equal to the non-intermittent generation installed capacity as a percentage of the Maximum Export Capacity.

8.3 Additional text has also been added to the legal text clarifying under what circumstances the eligibility for charge one credits is to be applied for both generation dominated sites and demand dominated sites.

8.4 The legal text amends paragraph 6.3 of Schedule 17 and amends paragraph 6.5 of Schedule 18.

9 Code Specific Matters

Modelling Specification Documents

9.1 Not applicable

Reference Documents

9.2 Not applicable

10 Voting

10.1 The DCP 313 Change Report was issued to DCUSA Parties for voting on 22 March 2019.

Part 1 Matter: Authority Decision Required

DCP 313: Proposed Variation (Solution)

10.2 For the majority of the Parties that were eligible to vote, the sum of the Weighted Votes of the Groups in that Party Category which voted to accept the proposed variation was more than 50%.

10.3 DCUSA Parties' have voted and recommend to the Authority to determine that the proposed variation (solution) is accepted for DCP 313.

DCP 313: Implementation Date

10.4 For the majority of the Parties that were eligible to vote, the sum of the Weighted Votes of the Groups in that Party Category which voted to accept the implementation date was more than 50%.

10.5 DCUSA Parties' have voted and recommend to the Authority to determine that the implementation date is accepted for DCP 313.

The table below sets out the outcome of the votes that were received in respect of the DCP 313 Change Report that was issued on 22 March 2019 for a period of 15 working days.

DCP 313	WEIGHTED VOTING				
	DNO	IDNO	SUPPLIER	DISTRIBUTED GENERATOR	GAS SUPPLIER
CHANGE SOLUTION	Accept	n/a	Accept	n/a	n/a
IMPLEMENTATION DATE	Accept	n/a	Accept	n/a	n/a

Other Interested Party Comments

10.6 In addition to the DCUSA Party votes, the DCUSA Secretariat also received a response from the Flexible Generation Group voicing their support for the change. Their comments have been included in the consolidated party votes document (attachment 1) for completeness.

11 Recommendations

DCUSA Parties Recommendation

11.1 DCUSA Parties have voted on DCP 313 and in accordance with Clause 13.5 of the DCUSA, recommend to the Authority to determine that the Change Proposal be accepted and thus that the proposed variation to the DCUSA should be made.

12 Attachments

- Attachment 1 – DCP 313 Consolidated Party Votes
- Attachment 2 – DCP 313 Legal Text
- Attachment 3 – DCP 313 Change Proposal
- Attachment 4 – DCP 313 Consultations and Collated Responses
- Attachment 5 – DCP 313 Request for Information impact assessment
- Attachment 6 – DCP 313 Request for Information on mixed sites
- Attachment 7 – DCP 313 Impact Assessment Results and TNEI Impact Assessment