Proposed variation:	**Distribution Connection and Use of System Agreement (DCUSA) DCP268–DUoS Charging Using HH Settlement Data**		
Decision:	The Authority[1] directs this modification[2] be made[3]		
Target audience:	DCUSA Panel, Parties to the DCUSA and other interested parties		
Date of publication:	08 April 2019	Implementation date:	In accordance with clause 14.2 of Part1C of DCUSA 1 April 2021

Background

This proposed change to the DCUSA seeks to align settlement for both demand and generation for each half hour. For existing non-half hourly settled demand customers, profiled data would be used as a proxy for actual usage, while for generation, non-intermittent generation would be aligned with intermittent generation using half hour metered readings.

The Common Distribution Charging Methodology ('**CDCM'**) is used by Distribution Network Operators to calculate Distribution Use of System ('**DUoS'**) network charges for Low Voltage and High Voltage demand and, generation customers. CDCM customers are either Half-Hourly ('**HH**') settled, where appropriate metering has been installed, or Non-Half-Hourly ('**NHH'**) settled. Larger, non-domestic customers are typically HH settled, while domestic customers require a smart meter to be HH settled. In many cases, charges are borne by suppliers who recover the costs from consumers via different retail tariffs.

Currently, CDCM charges differ between HH and NHH customers. HH customers are charged a three level Red/Amber/Green ('**RAG**') unit rate charge based on consumption within each time band over a given day, while NHH customers are charged either a single or a two-rate unit charge[4]. Intermittent generation is paid single-rate unit credits, whereas non-intermittent generation is paid three-rate RAG unit credits.

Northern Powergrid, (the '**Proposer'**), considers that such differences in the tariff structures contribute to an unnecessary degree of complexity. As a result, the Proposer considers that they act as a barrier to creating new innovative tariff structures. This modification seeks to address this.

The modification proposal

DCP268 was raised on 14 March 2016. The modification focuses on the structure of the unit rate component (p/kWh) of the CDCM charges and proposes changes that will transition all customers to a time-band charging basis.

DCP268 proposes to change the CDCM tariff structure in the following ways -

[1] References to the "Authority", "Ofgem", "we" and "our" are used interchangeably in this document. The Authority refers to GEMA, the Gas and Electricity Markets Authority. The Office of Gas and Electricity Markets (Ofgem) supports GEMA in its day to day work. This decision is made by or on behalf of GEMA.
[2] 'Change' and 'modification' are used interchangeably in this document.
[3] This document is notice of the reasons for this decision as required by section 49A of the Electricity Act 1989.
[4] Two rate domestic unit charges align with peak / off peak contracts and may require separate metering.

- Charge all CDCM demand customers a three-rate, time of use RAG unit charge, for both domestic aggregated and non-domestic aggregated customers (current NHH customers)
- Charge all unmetered supplies an analogous Black/Yellow/Green ('BYG') unit rate charge
- Both intermittent and non-intermittent generation receiving the same unit rate credits, on a RAG basis, relating to each half-hour.

As a result of these proposed changes, the existing 33 tariff structure bands will reduce to 16.

The allocation of NHH customers' individual consumption to the RAG/BYG bands will be based on each customer group's load and coincidence factors. These factors will be derived from a mix of meter and profile data for NHH metered supplies, and from data from the grid supply point for unmetered NHH supplies.

DCP268 will require Distributors to amend their billing systems to cater for these new tariffs and use of RAG and BYG. It has been noted that where Distributors do not have delinked tariffs[5], additional work will be required to deliver this change proposal and ensure data validation.[6]

DCUSA Parties' recommendation

DCP268 was submitted to us for decision on 20 July 2017. On 20 October 2017[7] we sent back DCP268 to the Panel for further work. We asked for more information on the impact of the proposal on intermittent generation credits and further assessment of the implementation date.

Following our decision to send back DCP268, the Working Group updated their modelling for intermittent generation and conducted a further consultation asking for additional comments and views on a revised implementation date.

We received the revised DCP268 on 23 May 2018. In two party categories where votes were cast (no votes were cast in the DG party category),[8] there was majority (>50%) support for the proposal and the proposed implementation date. One party category unanimously agreed to reject the proposal and its implementation date. In accordance with the weighted vote procedure, the recommendation to us is that DCP268 is accepted.

In this revised proposal, an implementation date of 1 April 2020 was submitted. The outcome of the weighted vote is set out in the table below:

DCP268 (revised)	WEIGHTED VOTING (%)							
	DNO		IDNO/OTSO		SUPPLIER		DG	
	Accept	Reject	Accept	Reject	Accept	Reject	Accept	Reject
CHANGE SOLUTION	79	21	0	100	100	0	n/a	n/a
IMPLEMENTATION DATE	79	21	0	100	86	14	n/a	n/a

[5] Delinked tariffs are used by some licensees, where alternative information to that in the NHH data flow (the D0030) is used to determine which unit rate will be applied at different times.
[6] Distributors without delinked tariffs will need to amend their billing systems to cater for these new tariffs and the use of RAG and BYG in preference to the settlement time pattern regimes.
[7] https://www.ofgem.gov.uk/publications-and-updates/authority-decision-send-back-dcp268-duos-charging-using-hh-settlement-data
[8] There are currently no gas supplier parties.

Our decision

We have considered the issues raised by the proposal and the revised Change Declaration dated 16 May 2018. We have also considered and taken into account the vote of the DCUSA Parties on the proposal, and concluded that:

- implementation of the modification proposal will facilitate better the achievement of the Applicable Charging Methodology objectives[9]; and
- directing that the modification be made is consistent with our principal objective and statutory duties.[10]

Reasons for our decision

We consider this modification proposal will facilitate Applicable Charging Methodology Objectives 2, 3 and 4 better, and has a neutral impact on the other relevant objectives.

Second Applicable Charging Methodology Objective – that compliance with the Relevant Charging Methodology 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 the participation in the operation of an Interconnector

The majority of DCUSA voting parties argued that Objective 2 is facilitated better as the tariff structure will be simplified (reduced from 33 to 16) and allows greater flexibility for the supply industry, facilitating the move to offer time of use tariffs in the future. They consider that this will allow Suppliers to provide more innovative tariffs which will ultimately facilitate greater competition. Exceptions are noted below.

Parties argued that the use of RAG time bands will reflect more accurately the costs of the distribution system, improving cost reflectivity and removing existing distortions. For distribution connected intermittent generation, credit values will be better aligned with demand, as for non-intermittent generation. This addresses concerns raised with the current tariff structure where it under-rewards distribution connected intermittent generation active at peak (red periods) and over-values distribution connected generation during off-peak (green periods).

One respondent to a consultation conducted by the Working Group recognised that the relative impact from this change to solar and wind will vary, given differences in generation over summer and winter, and when the RAG bands occur. The Working Group agreed that greater alignment to costs could be resolved by a Seasonal Time of Day tariff, but noted this is outside of the scope of this proposal.

One DCUSA voting party disagreed that this objective will be facilitated better by DCP268. Instead they commented that competition might be stifled as the proposed changes might cause unnecessary and burdensome costs to new market entrants and existing parties. It was also argued that customers will not be able to make a reasonable estimate of the charges they will be liable for, given that their consumption profile is based on aggregated energy consumption estimates.

[9] The DCUSA Charging Objectives (Relevant Objectives) are set out in Standard Licence Condition 22A Part B of the Electricity Distribution Licence and are also set out in Clause 3.2 of the DCUSA.
[10] The Authority's statutory duties are wider than matters that the Parties must take into consideration and are detailed mainly in the Electricity Act 1989 as amended.

Our position

We agree that DCP268 will help facilitate greater flexibility for Suppliers to offer innovative products as a result of reducing the number and complexity of the distribution tariff structures. We accept that the proposal is better than the current flat rate for distribution connected intermittent generation technologies, as it rewards those who generate at peak where they can better offset demand, and removes existing distortions based on technology.

We have some concerns about the locational aspect of increasing some generation credits during red periods, but acknowledge that is outside of the scope for this proposal and will be considered as part of the Electricity Network Access and Forward-Looking Charging Significant Code Review ('**Electricity Network Access SCR'**) currently underway[11].

With regards to arguments that costs for new entrants may increase, we consider that the changes proposed are justified as they simplify settlement arrangements, and prepare parties for HH settlement. As for arguments relating to consumers, they can elect to install a smart meter and consider a time of use domestic tariff, should they consider a profile based on aggregated consumption is not representative of their usage.

On balance, we consider that the proposal will help improve competition.

Third Applicable Charging Methodology Objective – that compliance with the Relevant Charging Methodology results in charges that, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by a Distribution Services Provider in its Distribution Business

The majority of DCUSA voting parties noted that, assuming appropriate metering is in place, this proposal will reflect more accurately costs of using the distribution network and provide greater cost reflectivity, as costs will be based upon each Supplier's aggregate customer profile, rather than being smeared across all consumers.

The majority of DCUSA voting parties argue that the removal of the intermittent/non-intermittent distinction will result in more cost-reflective tariffs compared to the current position, which as we note above, under-rewards distribution connected intermittent generation active at peak times and over-values distribution connected intermittent generation outside peak times.

The impact assessment provided in the change proposal indicates generation credits will increase in all regions as a result of this change proposal. This varies from a minimum of 1.14% to a maximum of 18.42%, dependent on region and alignment of intermittent generation to demand peaks. The impact assessment also notes that some demand customers face an overall increase in charges as a consequence of NHH profiling and changes to intermittent generation settlement. These changes do however vary considerably by region, with the Domestic Unrestricted tariff ranging from a decrease of 0.02% to an increase of 2.60%.

Overall, most DCUSA voting parties argued that cost reflectivity will be increased by this proposal. However, one DCUSA voting party disagreed, arguing that removing the distinction between intermittent and non-intermittent generation will reward all generation rather than that which has the greatest 'potential' or are more 'capable' of deferring and avoiding future distribution network reinforcement.

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[11] https://www.ofgem.gov.uk/electricity/transmission-networks/charging/reform-network-access-and-forward-looking-charges

Concerns were also raised about how this change proposal would increase cost reflectivity as profiles are not based on actual data covering all customers. Consumption data estimates will remain based on profile data used today, sampled across a region, and not reflect actual consumption in each time band. Furthermore, consumers who change usage patterns will not be charged different prices, and thus argue that an increase in cost reflectivity cannot be achieved. It was further argued that installing smart meters and introducing time of use tariffs, will better deliver the benefits which this change purports to deliver, but without additional indirect cost.

One DCUSA voting party also noted that in May 2016 Ofgem published a conclusions paper on HH settlement[12] which stated that there were no immediate barriers to elective HH settlement within the distribution charging arrangements. The party believes that a more expedient solution would be to encourage Suppliers to settle on HH aggregate data as smart metering is installed.

Our position

On balance, we accept the position of the DCUSA voting parties that the proposal will allow for network use costs to be more cost reflective. Distribution connected generation, regardless of technology and intermittency, will face the same reward structures based on *when it produces, relative to demand*. Further refinement of the signal needed to reward generation, where it can defer and avoid future network reinforcement, will be considered as part of the Electricity Network Access SCR currently underway.

While Distribution Network Operators will benefit from more cost reflective tariffs, we accept that moving customers to HH settlement is needed for the full benefits of greater cost reflectivity to be realised. However, we accept that the proposed change is better than the current arrangements and will help facilitate this transition.

Fourth Applicable Charging Methodology Objective – so far as is consistent with the first three Applicable Charging Methodology Objectives, the Relevant Charging Methodology, so far as is reasonably practicable, properly takes account of developments in a Distribution Services Provider's Distribution Business

The majority of DCUSA voting parties argued that Objective 4 is facilitated better by changes brought by DCP268 and two parties further explained that this was the case given these sit alongside developments already underway.

However, a minority of DCUSA voting parties disagreed, stating that, whilst a clear decision on HH settlement had yet to be taken, these similarities could duplicate the existing work creating unnecessary time and monetary costs. They also considered that, given the current plan for the majority of customers to have smart meters installed by 2020, this modification might not offer benefits at all.

One DCUSA voting party also noted that there could potentially be a significant impact as a result of the work currently being considered by Ofgem's Electricity Network Access SCR. Changes from this work could potentially alter tariff structures with a knock on impact on both Balancing Use of System and DUoS charging/billing arrangements.

Furthermore, one DCUSA voting party judged the proposed implementation date (1 April 2020) to be unlikely to be achievable as the change would require significant changes to Distributors' billing systems. In their view, this could take a minimum of 24 months to design, build, successfully test and implement fully.

[12] https://www.ofgem.gov.uk/publications-and-updates/elective-half-hourly-settlement-conclusions-paper

Our position

We agree with the position that the proposal properly takes into account future developments, including facilitating HH settlement, and rollout of smart meters.

We acknowledge concerns as to the practicality of completing all changes within the timeframe currently proposed. The earliest possible date for implementation for this change is now 1 April 2021 as charges for 2019/20 and 2020/21 are already set, given the requirement for a 15 months' notice period (as required by DCP178). We are also aware of the concerns raised by some consultation respondents, in particular Distributors that do not have de-linked tariffs.

In making our decision, we acknowledge the interaction between this proposal and changes introduced by BSC Modification P300[13] and supporting DCUSA change DCP179[14], which uses 'pseudo' profile classes which are similar to the proposal. We believe that DCP268 extends DCP179, as DCP179 enables aggregate billing for specific groups of HH metered customers whilst DCP268 uses HH profiled data to transition all NHH customers to a time-band charging basis.

In reaching our decision, we have also taken into consideration the potential interaction of this modification with our Electricity Network Access SCR. While some of the changes from this modification have the potential to be superseded by recommendations and modifications that may result from the SCR, we understand that the system changes required to implement this modification do not impact significantly on the scope, and will not warrant delaying implementation until the SCR has concluded.

In accordance with clause 14.2 of DCUSA, the deemed implementation date is 1 April 2021 as our decision to approve DCP268 cannot come into effect on 1 April 2020 as the required notice period will not be met.

Decision notice
In accordance with standard licence condition 22.14 of the Electricity Distribution Licence, the Authority directs that modification proposal DCP268: *DUoS Charging Using HH Settlement Data* be made.

Andrew Burgess
Deputy Director, Charging and Access
Signed on behalf of the Authority and authorised for that purpose

[13] https://www.elexon.co.uk/mod-proposal/p300/

[14] https://www.dcusa.co.uk/Lists/Change%20Proposal%20Register/DispForm.aspx?ID=144&Source=https%3A%2F%2Fwww%2Edcusa%2Eco%2Euk%2FSitePages%2FActivities%2FChange%2DProposal%2DRegister%2DArchive%2Easpx%23InplviewHash35f4ef25%2Df112%2D41cb%2D9311%2Ddac2d3455147%3D&ContentTypeId=0x0100684A1DE09E1F9740A444434CF581D435