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Proposed variation:	**Distribution Connection and Use of System Agreement (DCUSA) DCP 227 – Removing the inconsistency in the application of Peaking Probabilities in the Common Distribution Charging Methodology (CDCM)**		
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:	21 October 2015	Implementation date:	01 April 2017

Background

This change proposal removes the inconsistency in where peaking probabilities[4] are applied and where they are not in the Common Distribution Charging Methodology (CDCM).

Currently, the CDCM has a different set of rules for domestic (household) customers and small business and other non-domestic customers on the unrestricted tariffs compared to the rules for those on tariffs with multiple unit rates when allocating the costs of each network level on the basis of contribution to system simultaneous maximum load.[5]

The network level cost is allocated to some tariffs on the assumption that all assets at all levels peak at the time of system peak, but the network level cost is allocated to the other tariffs in a way which reflects the peaking probabilities of each network level.

The modification proposal

DCP 227 was raised by British Gas in February 2015. The proposal seeks to remove the inconsistency in the CDCM by ensuring costs are allocated in a way which utilises peaking probabilities for all demand customer tariffs.

The two methodologies currently used in the CDCM are:

- Domestic unrestricted and small non-domestic unrestricted tariffs: the CDCM uses the ratio of the tariff group coincidence factor[6] to load factor[7]. The peaking probabilities at the various network levels have no impact on the allocation of cost, in effect assuming that all network level assets peak at the time of system peak.

- Tariffs with multiple rates: the CDCM allocates the costs of each network level on the basis of contribution to the system simultaneous maximum load. The ratio of the coincidence to the load factor is replaced with a coefficient, which is calculated to reflect the peaking probabilities of each network level.

The proposal amends the discrepancy in the tariff calculation by ensuring costs are allocated in a way which utilises peaking probabilities for all demand tariffs. This will be achieved by replacing the ratio of the coincidence factor to the load factor with a

[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] Peaking probability: represents the probability that an asset at a particular network level would experience maximum load during a distribution time band.
[5] System simultaneous maximum load: The maximum load for the Grid Supply Point (GSP) Group as a whole.
[6] Coincidence factors: the load of a user group at the time of system simultaneous maximum load, relative to the maximum load level of that user group.
[7] Load Factors: the average load of a user group over the year, relative to the maximum load level of that user group.

coefficient calculated by the following procedure to reflect the peaking probabilities of each network level::

a) Calculate the ratio of coincidence factor to load factor that would apply if units were uniformly spread within each time band[8], based on the estimated proportion of units recorded in each relevant time pattern regime that fall within each distribution time band and the assumption that the time of system simultaneous maximum load is certain to be in the red or black (as appropriate) distribution time band.

b) Calculate a correction factor for each user type as the ratio of the coincidence factor to load factor, divided by the result of the calculation above.

c) For each network level and each unit rate, replace the ratio of the coincidence factor to the load factor in the above formula with the ratio of coincidence factor (to network level asset peak) to load factor that would apply given peaking probabilities at that network level if units were uniformly spread within each time band, multiplied by the correction factor.

d) The coefficient calculated for the non-half hourly and half hourly unmetered supplies tariffs will be determined by aggregating these tariffs to produce one value.

The working group agreed that a single approach should be used when allocating the costs of each network level on the basis of contribution to system simultaneous maximum load and that the preferred approach is to use peaking probabilities because:

- in some DNO[9] areas the time that the network levels peak is significantly different from the time of system peak. In these cases, much of the costs of the network are driven by what is occurring outside of the time of system peak. By bringing peaking probabilities into the calculations, DCP 227 would introduce greater cost reflectivity of the costs incurred on the network.

- the coincidence factor approach does not work for allocating costs of multiple unit rates and therefore could not be applied to all demand tariffs.

The proposer and the majority of the working group considered that DCP 227 facilitates DCUSA Charging Objective 3.2.3[10] better:

- by bringing peaking probabilities into the calculations, DCP 227 would introduce greater cost reflectivity of the costs incurred on the network (network levels peaks often occur at different times to the system peak);
- by removing an inconsistency in the allocation of network costs to different tariffs.

DCUSA Parties' recommendation

The Change Declaration for DCP 227 indicates that DNO, IDNO/OTSO[11], Supplier, DG[12] and Gas Supplier parties were eligible to vote on DCP227. In each party category where votes were cast (no votes were cast in the DG party, Gas Supplier or IDNO/OTSO

[8] The CDCM has five time bands which reflect periods of network loading - labelled amber, black, green, red and yellow
[9] Distribution Network Operator
[10] 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.
[11] Independent Distribution Network Operator/Offshore Transmission System Operator
[12] Distributed Generation

category),[13] there was majority (>50%) support for the proposal and for its proposed implementation date. In accordance with the weighted vote procedure, the recommendation to the Authority is that DCP 227 is accepted. The outcome of the weighted vote is set out in the table below:

DCP227	WEIGHTED VOTING (%)									
	DNO		IDNO/OTSO		SUPPLIER		DG		Gas Supplier	
	A	R	A	R	A	R	A	R	A	R
CHANGE SOLUTION	72%	28%	n/a	n/a	100%	0%	n/a	n/a	n/a	n/a
IMPLEMENTATION DATE	72%	28%	n/a	n/a	67%	33%	n/a	n/a	n/a	n/a

Our decision

We have considered the issues raised by the proposal, Change Declaration and Change Report dated 16 September 2015. We have considered and taken into account the vote of the DCUSA Parties on the proposal which is attached to the Change Declaration. We have concluded that:

- implementation of the modification proposal will better facilitate the achievement of the DCUSA Charging Objectives;[14] and
- directing that the modification be made is consistent with our principal objective and statutory duties.[15]

Reasons for our decision

We consider that this modification proposal will facilitate better DCUSA Charging Objective 3.2.3 and have a neutral impact on the other applicable objectives.

DCUSA Charging Objective 3.2.3 – that compliance by each DNO Party with the Charging Methodologies results in charges which, so far as is reasonably practicable after taking account of implementation costs, reflect the costs incurred, or reasonably expected to be incurred, by the DNO Party in its Distribution Business

Unrestricted tariffs in the CDCM are currently not determined using peaking probabilities. The network level cost is allocated on the assumption that all assets at all network levels peak at the time of system peak. However, we know that in some DNO areas the time that the network levels peak is significantly different from the time of system peak. In these cases, much of the costs of the network are driven by what is occurring outside of the time of system peak. By bringing peaking probabilities into the calculations, we agree that this proposal will introduce greater cost reflectivity of the costs incurred on the network.

One working group member did not agree with this view. They noted that the reason unrestricted tariffs in the CDCM are not determined using peaking probabilities is due to the difficulty in determining when customers use the network, as this data is unavailable

[13] There are currently no gas supplier parties.
[14] 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.
[15] 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.

for unrestricted customers. As a result their view is that the proposal is not an improvement to the cost reflective nature of the CDCM.

We agree that it is difficult to determine precisely how much more cost reflective this approach will be given the inherent difficulties in getting the data on non-half hourly customers but we are convinced that it should be more cost reflective. We agree that it is appropriate to use a single calculation for all demand tariffs, when allocating the costs of each network level on the basis of contribution to system simultaneous load, as this would have the effect of making the methodologies in the CDCM more consistent. We also agree that it is appropriate to remove this inconsistency by ensuring costs are allocated in a way which utilises peaking probabilities for all demand tariffs and are of the view that this proposal will introduce greater cost reflectivity on the network, and better facilitate DCUSA charging objective 3.2.3.

We note that the impact of this modification will differ in the different DNO areas and to different customer types. This difference in the impact is in some instances linked to the different time bands used by the DNO in question. As the implementation date is April 2017 this gives sufficient time to suppliers and other interested parties to adjust for this change. If necessary, it also gives time for DNOs in areas where this modification will have a more significant impact to consider if their time bands remain correct and appropriate.

One party expressed concern at the implementation date for DCP 227; they requested that the implementation date be April 2018 rather than April 2017. We note the implementation date of April 2017 gives all relevant parties more than 15 months of advance notice of the change, which we think is sufficient in this case.

Decision notice

In accordance with standard licence condition 22.14 of the Electricity Distribution Licence, the Authority hereby directs that modification proposal DCP227: Removing the inconsistency in the application of Peaking Probabilities in the Common Distribution Charging Methodology is made.

Ian Rowson
Associate Partner, Regulatory Finance and Governance

Signed on behalf of the Authority and authorised for that purpose