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Electricity distribution charging: decision on the methodology for higher voltage import charges

Final decision

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Overview:

The distribution network operators (DNOs) submitted their proposals for an Extra High Voltage Distribution Charging Methodology (EDCM) on 1 April 2011. This document sets out our decision to approve the methodology for import charges (ie demand) subject to three conditions. New charges for demand customers connected at higher voltages will apply from 1 April 2012. The DNOs have 28 days to make representations or objections to the conditions. Other parties can also comment.

The Authority has decided to delay the introduction of EDCM export (ie generator) charges (subject to them being approved), particularly to provide clarity around the arrangements for pre-2005 connected generators. Our current thinking is to grant them a time limited exemption from use of system charges. Accordingly, we are deferring our decision on EDCM export charges. If we approve the DNOs' methodology, charges would apply from 1 April 2013 (or possibly later). We will consult further on these issues in late September/early October 2011.

Context

Delivery of the electricity distribution structure of charges project is a priority for Ofgem, as we consider it will drive considerable improvements for consumers and other users of the distribution networks. Given the level of future investment required on the distribution network, and the challenges the network will face with the move to a low carbon economy we think it is important to ensure common, cost reflective charging arrangements are put in place, which can be adapted over time to reflect network developments.

Historically, each distribution network operator used individual methodologies to set customer use of system charges. This changed for customers at the lower voltages on 1 April 2010 when the Common Distribution Charging Methodology (CDCM) was introduced. The CDCM charges customers on an average basis, depending on the type of customer. This document sets out the next step in the structure of charges project: our approval of the Extra High Voltage Distribution Charging Methodology (EDCM) in respect to import charges (ie as they apply to demand customers) and subject to three conditions. Charges calculated using this methodology will apply to import charges from 1 April 2012 and determine charges for individual customers on a “site-specific” basis.

This document also explains why we are delaying our decision on the EDCM as it relates to export (ie generator) charges. On 11 August 2011 we outlined our current thinking to grant a time limited exemption to distributed generation that connected on pre-2005 terms. This is likely to result in a material number of generators becoming exempt from use of system charges. This affects the charges of the remaining generators under the methodology proposed by the DNOs. We are therefore unable to conclusively assess the impact on the latter group’s charges, and whether EDCM export charging needs to be changed, until we have made a decision on the time limited exemption. We will consult on both the time limited exemption and the way forward on the EDCM for export charges in late September or early October.

Associated documents

- Delivering the electricity distribution structure of charges project, 1 October 2008 (Reference number: 135/08) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=447&refer=Networks/ElecDist/Policy/DistChrgs

- Next steps in delivering the electricity distribution structure of charges project: decision document, 20 March 2009 (Reference number: 24/09) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=480&refer=Networks/ElecDist/Policy/DistChrgs

- Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements, 31 July 2009 (Reference number:90/09) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=487&refer=Networks/ElecDist/Policy/DistChrgs

- Electricity distribution structure of charges: the common distribution charging methodology at lower voltages, 20 November 2009 (Reference number: 140/09) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=533&refer=Networks/ElecDist/Policy/DistChrgs

- Electricity distribution charging boundary between higher (EDCM) and lower (CDCM) voltages, 22 July 2010 (Reference number: 90/10) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=576&refer=Networks/ElecDist/Policy/DistChrgs

- Decision on revised submission and implementation dates for the EHV Distribution Charging Methodology (EDCM), 22 September 2010 (Reference number: 120/10) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=651&refer=Networks/ElecDist/Policy/DistChrgs

- Consultation letter on a licence change to the boundary between the Common Distribution Charging Methodology and the EHV Distribution Charging Methodology related to Licensed Distribution Network Operators, 15 March 2011 (Reference number:31/11) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=666&refer=Networks/ElecDist/Policy/DistChrgs

- EHV Distribution Charging Methodology (EDCM) report, 13 April 2011 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=679&refer=Networks/ElecDist/Policy/DistChrgs

- Charges for pre-2005 distributed generators' use of Distributed Network Operators' (DNOs) distribution systems - proposed guidance, 9 May 2011 (Reference number: 58/11) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=684&refer=Networks/ElecDist/Policy/DistChrgs

- Electricity distribution charging methodologies: distribution network operators' (DNOs') proposals for the higher voltages, 20 May 2011 (Reference number: 67/11) http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=687&refer=Networks/ElecDist/Policy/DistChrgs

- Use of system charges for distributed generators (DG) – update on current thinking, 11 August 2011 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=759&refer=Networks/ElecDist/Policy/DistChrgs

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Executive Summary

Purpose of the methodology

The electricity distribution structure of charges project is an important contribution to our objective of protecting the interests of current and future network users. A Common Distribution Charging Methodology (CDCM) has been in place since 1 April 2010 for customers at lower voltages. The Extra High Voltage (EHV) Distribution Charging Methodology (EDCM) for customers at higher voltages is the remaining element of the structure of charges project.

With an estimated £2.2 billion in network reinforcement costs (of which £1.6 billion is at EHV) over the fifth Distribution Price Control Review period and developments such as the increasing prevalence of distributed generation, we want to ensure that users of these networks are encouraged to make the most efficient use of the existing infrastructure and contain the amount of new investment that customers have to pay for. We also aim to ensure that the cost of maintaining the networks and of funding new investment is allocated fairly across different customers. We are keen for rewards to be available to users that provide a benefit to the network, such as those who manage their demand patterns to avoid using the network at peak times.

Our decision

We are approving the EDCM for import charges to apply from 1 April 2012 (ie as they apply to demand customers), subject to three conditions. We consider that the methodology as it relates to import charges meets the Relevant Objectives set out for the project, which include the promotion of competition and ensuring charges appropriately reflect costs. The methodology is largely common, which makes it easier for suppliers and licensed distribution network operators (LDNOs) to operate across distribution network operator (DNO) areas. It gives price signals about where it is cheapest to connect on the network while ensuring charges appropriately reflect the DNO’s costs. Importantly, the methodology gives customers an opportunity to manage their charge.

We are placing three conditions as part of our approval. Under the licence, the DNOs have 28 days to make representations on or objections to these conditions (ie until 5 October 2011). The first two conditions must be fulfilled by 30 November 2011, that is, prior to the introduction of EDCM import charges. Condition 1 changes the way discounts on charges for LDNOs are calculated. We think the DNO’s proposed approach gives LDNOs an excessive margin in some cases which could give them an unfair advantage over the DNOs when competing for some new connections. Condition 2 improves the cost reflectivity of the locational component of the charge that estimates the future costs associated with reinforcing the network in that area.

Condition 3 requires the DNOs to further investigate and consult on the issue of how spare capacity on assets used by customers should be treated when allocating costs.

The DNOs must submit a report to us with a recommendation on the issue by 1 June 2012 (ie after the introduction of EDCM import charges).

Deferral of decision on EDCM for export charges

The Authority has decided that the introduction of common charging arrangements for distributed generators (DG) connected at high voltages (subject to their approval) should be delayed, particularly to provide greater clarity around the arrangements for DG who connected on pre-2005 terms. Our current thinking is that these DG should be given a time limited exemption from use of system charges. Accordingly, we are deferring our decision on the methodology as it applies to DG (ie export charges). Should we approve EDCM charges for DG, we expect that charges would apply from 1 April 2013 (or possibly later). We will consult further in late September or early October 2011 on the pre-2005 arrangements and the way forward on EDCM charges for DG.

Impact and assistance to customers

The introduction of the EDCM for import charges will result in some rebalancing of charges across higher voltage customers as well as between EDCM and CDCM customers. Around three quarters of higher voltage customers will see either no change or a reduction in the distribution charge component of their electricity bill. However, some customers will see substantial increases in their charge in percentage and/or absolute terms.

In light of this, we set out our expectation that DNOs will provide assistance to the most affected customers, in terms of outlining the options provided by the EDCM that may allow them to reduce their charge. One of these options is to enter a demand side management agreement and in light of some uncertainty around the availability of these arrangements, we expect DNOs to clarify who can enter these arrangements and on what terms.

A number of respondents to our consultation highlighted volatility of charges and difficulty in "seeing" the charging cost signals as potential issues with the EDCM. We outline in the document that we expect the DNOs to make significant progress on these issues in the short to medium term.

Areas for further development and open governance

A key component of the structure of charges project is to bring the charging methodologies under the existing industry codes and agreements. Previously, only DNOs could amend their charging methodologies, going forward it will be open to other industry stakeholders to propose changes. In this document, we identify some areas that stakeholders may want to give consideration to through this process. These relate to other issues around the way discounts for LDNOs are calculated and how minor power flows are treated when calculating a customer's charge.

1. Our Decision

Approval of EDCM for demand customers subject to conditions

Our approval

1.1. The distribution network operators (DNOs)[1] are required by their licence[2] to bring forward a common charging methodology at the higher voltages which is capable of approval by the Authority. The Extra High Voltage Distribution Charging Methodology (EDCM), as submitted to us on 1 April 2011, constitutes the DNOs' proposals for a common charging methodology to fulfil this requirement.

1.2. In respect of charging for import (demand) customers, the Authority has decided to approve the EDCM proposal for implementation on 1 April 2012, subject to the conditions set out in Chapter 2. The approval has immediate effect. The Direction under the licence[3] to approve the EDCM for import charges is in Appendix 2 of this decision document.

The Relevant Objectives and related requirements

1.3. Our approval is on the basis that, having regard to our principal objective and duties under the Electricity Act 1989, the EDCM for import charges achieves in the round the Relevant Objectives set out under the licence.[4] We outline more specifically some of our reasons against the Relevant Objectives below.

50A.7 The first Relevant Objective is that compliance with the EDCM facilitates the discharge by the licensee of the obligations imposed on it under the Act and by this licence.

- We consider that the EDCM for import charges facilitates the licensees' obligations under the Act and the licence. In particular:
    - section 9(1) of the Act which places a duty on DNOs to develop and maintain an efficient, co-ordinated and economical system of electricity distribution; and
    - SLC 50A of the licence which concerns the development and implementation of an EHV Distribution Charging Methodology.

[1] Electricity Distributors who are Distribution Services Providers under SLC 1, referred to hereafter as DNOs.
[2] Standard licence condition (SLC) 50A of the DNOs' distribution licences.
[3] Made pursuant to SLC 50A.20 and dated 6 September 2011.
[4] SLC 50A.7-10.

50A.8 The second Relevant Objective is that compliance with the EDCM 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.

- The commonality of the methodology should encourage competition by reducing barriers to entry for suppliers and Licensed Distribution Network Operators (LDNOs) operating in multiple DNO areas. They will now only have to understand a single charging methodology (with the exception of the method used to calculate the locational component of the charge) for import charges.

- The methodology provides specific charges and discounts to LDNOs in a more simple and transparent manner than the current methodologies employed by the DNOs for EDCM-connected LDNOs (noting that we are setting a condition to further improve the discount method). This should improve competition as LDNOs will have more clarity and certainty of their likely charges and discounts, in particular through the "extended Method M" model that is used to calculate discounts where the LDNO has CDCM-connected end customers.

50A.9 The third Relevant Objective is that compliance with the EDCM 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 licensee in its Distribution Business.

- Charges are dependent on users' agreed capacity, consumption at system peak and the network assets utilised. Calculating charges based on such cost drivers helps to ensure that charges appropriately reflect the costs imposed by users on the network.

- A key part of the charge (17 per cent on average), the locational component, reflects the estimated future costs of reinforcing each part of the network used by the customer. This results in this component being higher in more congested parts of the network reflecting the greater likelihood of future reinforcement in these areas and lower in less congested parts of the network reflecting spare capacity on existing assets.

- The methodology provides for specific recognition of where users have entered demand side management arrangements to reduce costs at system peak. It reflects the potential cost savings of such arrangements by calculating part of the charge based on the users' capacity that is constrained under the arrangement, rather than their maximum import capacity.

50A.10 The fourth Relevant Objective is that, so far as is consistent with the first three Relevant Objectives, the EDCM, so far as is reasonably practicable, properly takes account of developments in the licensee's Distribution Business.

- Specific charges and discounts are provided for EDCM-connected LDNOs as described above, reflecting the increased prevalence of LDNOs.

- The methodology reflects and includes mechanisms that encourage management of demand, such as demand side management agreement and a charge for units consumed during system peak. This can help reduce system losses as well as a reduction in overall demand, which is an important part of the move to a low carbon economy.

- The locational charges signal to new users to connect in areas with spare capacity rather than in congested areas. Where there is congestion, the signals encourage current users to manage their usage. In light of the significant amount of reinforcement estimated to be required in the networks (£2.2 billion over the DPCR5 period, of which £1.6 billion is at EHV), these behaviours help to ensure more efficient investment and ultimately lower bills for customers.

1.4. The methodology will be subject to open governance. Industry participants will be able to suggest changes to the methodology that should help ensure it is kept up to date with developments in the distribution network and continually improved. The open governance arrangements are contained in the Distribution Connection and Use of System Agreement (DCUSA). Under open governance any DCUSA party or other parties materially affected by the methodology (with the permission of the Authority) can propose a modification to the EDCM. There is a licence requirement[5] on the DNOs to incorporate the EDCM for import charges into the DCUSA prior to the introduction of new charges on 1 April 2012.

Conditions of our approval

1.5. We have considered consultation responses in coming to our decision, and following responses and further analysis, we decided to place three conditions on our approval. We set out our conditions in Table 1 below, with more detailed explanation in Chapter 2.

Table 1 – conditions of our approval (Chapter 2)

No	Condition	Implementation date
1	To reduce the number of customer categories for LDNO discounts	30 November 2011
2	To modify the method of sense checking branch incremental costs in LRIC	30 November 2011
3	To review the method for calculating network use factors	1 June 2012

1.6. We have also set out a number of expectations on the DNOs in relation to assisting customers with the new charges (Table 2) and have flagged certain areas that we recommend be reviewed by the DNOs and others and progressed under open governance (Table 3).

[5] SLC 20A.11.

Table 2 – customer assistance measures (Chapter 3)

No	Customer measure
1	To provide assistance to customers on managing their charge
2	To formalise the arrangements for demand side management agreements
3	To assess measures to reduce volatility
4	To provide visibility of cost signals

Table 3 – areas for potential further development (Chapter 4)

No	Issue
1	Consideration of peak time reactive flows
2	LDNO discount on 20 per cent of residual revenue
3	Customer categories – consideration of assets below the voltage of connection
4	Capping of LDNO discounts at 100 per cent

Derogations

1.7. The DNOs have not formally submitted any requests for derogations from the EDCM. If there were circumstances where the assumptions in the methodology were inappropriate for some customers then we would expect the DNOs to identify these and request a derogation to avoid inappropriate charges. We expect that these would represent exceptional circumstances. As part of the derogation request, the DNO would need to propose a modification to correct the issue.

1.8. Any request for a derogation must be brought forward with sufficient time to enable a proper consultation period and for illustrative charges to be published prior to the commencement of the EDCM for import charges on 1 April 2012.

Deferral of decision on EDCM for export charges

1.9. In our letter to stakeholders of 11 August 2011,[6] we stated that due to the need to resolve issues in relation to charging pre-2005 distributed generation (DG)

[6] Use of system charges for distributed generators (DG) – update on current thinking http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=759&refer=Networks/

for use of system charges, we have decided that it will not be possible to introduce EDCM export charges for DG until April 2013 (or possibly later). We stated that this delay should enable stakeholders to understand the impact of our decision on pre-2005 charging prior to any implementation of the EDCM for DG.

1.10. Due to the way the EDCM currently calculates generator charges, removing some generators would be likely to have a material impact on the charges of other generators, [7] if the EDCM were implemented as it was proposed by the DNOs. Until we decide which generators will be exempt, and thus understand the impact on the remaining generators' charges, we do not consider it appropriate to make a decision on the methodology for DG.

1.11. We also stated in the letter that this delay should also allow us to assess and make a decision on whether the methodology (as it applies to DG) is appropriate given the treatment of pre-2005 DG. This includes taking into account the consultation responses received from generators and other parties in relation to the DNOs' proposals under the EDCM for generator charging.

1.12. During the interim period (ie until 1 April 2013, or possibly later), we do not propose to make changes to the existing arrangements for DG. In particular, we do not propose to change the EDCM/CDCM boundary, so those DG currently classified as CDCM will remain so and will likely continue to receive net credits.

1.13. We intend to publish a consultation on the time limited exemption and the way forward for EDCM generation charging in late September or early October 2011.

Implication of deferral of decision on generation on demand charging

1.14. The decision to defer the implementation of EDCM generation charges has two main impacts on charges for demand customers. The first arises due to how the revenue targets for EDCM and CDCM demand are determined and the second is due to the way the EDCM allocates costs between the import and export meter of mixed sites.

[7] On average, pre-2005 generators contribute proportionally more to the generation revenue target than they collectively pay. Accordingly, where they are removed, the charges of post-2005 generators will generally increase.

Impact on charges of demand customers

1.15. Deferring implementation of EDCM generation charges until April 2013 (or possibly later) means that the total recovery from EDCM generation will be lower than if all DG (pre-2005 and post-2005) were being charged under the EDCM. This difference is recovered from both EDCM and CDCM demand customers.[8] Our analysis indicates that this impact on these customers is small or negligible.[9]

1.16. In the interim period until EDCM generation charges are implemented, EHV generators will continue to be charged under DNOs' existing methodologies.

Impact on mixed (demand and generation) sites

1.17. The second interaction between demand and generation charges in the EDCM is in the context of mixed sites. Costs associated with a mixed site's sole use assets are split across its demand and generation function according to their respective agreed capacities.

1.18. We propose the same split remains in the interim until EDCM generation charges are implemented. Where DNOs consider that calculating a charge for export on the basis of their current methodology and import on the basis of the EDCM is inappropriate we expect them to propose a modification to their current methodology for EHV generation charges.

Implementation timeframe for demand customers

1.19. As noted above, EDCM charges for demand customers will apply from 1 April 2012. We have decided to delay our decision on the EDCM for generation customers, as outlined above.

1.20. In our consultation, we asked whether stakeholders agreed with our proposal to implement the EDCM from 1 April 2012, or whether the phasing in of charges or delaying implementation was appropriate.

1.21. The majority of DNOs and LDNOs were in favour of implementing the EDCM from 1 April 2012 and the majority of generators were for delay. Suppliers were split roughly equally between implementation on 1 April 2012 and some form of delay or phasing (although the latter focussed on the impact on generators), and delay or phasing for some or all customers was preferred by three of the four demand

[8] This is because the EDCM and CDCM demand revenue targets are determined after recovery from EHV generators has been deducted.
[9] The average increase across all DNO areas against the DNO's April submission is 0.4%, although it is higher in SPD (1.5%) and SHEPD (1.9%). Some individual customers with a low EDCM charge have increases of 7-19% but in each case the increase is less than £900.

customers that responded. Further information on the response to our question on implementation is provided in Appendix 1.

1.22. We consider that charges for demand customers should apply from 1 April 2012 for a number of reasons:

- We think there has been sufficient notice of the change in charges, as the DNOs published illustrative charges a year in advance of implementation.
- We have already delayed the EDCM by a year and a key reason was so that DNOs could justify some of the significant increases and consult further with stakeholders – we are of the view that this has been achieved.
- The EDCM offers mechanisms to reduce charges and we expect the DNOs to provide specific assistance to the most affected customers to identify how they can do so.
- Delay would mean deferring the benefits for those experiencing decreases in their charge as well as the broader advantages of the EDCM such as the reduction of costs for suppliers from having a common method and the opportunities the EDCM provides customers to manage their charge.
- Phasing is complicated in terms of how it would be implemented and would have likely resulted in delayed implementation for all customers as we would have needed to consult on the phasing or delay option.
- Delay and phasing would reduce the cost reflectivity of use of system charges and would effectively result in cross subsidies between customers.

1.23. We note that around three quarters of customers will experience reductions in their charge. Despite some large increases remaining, only four demand customers responded to our most recent consultation, and did not bring forward new evidence that suggested that delay or phasing were necessary.

2. Conditions of our approval

2.1. The decision to approve the EDCM for import charges is subject to three conditions as detailed below.[10] Under the licence,[11] DNOs have 28 days within which representations or objections with respect to the conditions may be made. Other parties can also comment on these conditions.

Condition 1: to reduce the number of customer categories for LDNO discounts

2.2. The EDCM determines charges for EDCM-connected LDNOs depending on whether the LDNOs' end customer connects to a network level that would be covered by the EDCM[12] or the CDCM. Where the end customer is a CDCM customer, the charge is determined using an extension of the "Method M" model, which sits outside the methodology. The Method M model used to calculate discounts under the CDCM[13] allocates DNO costs to the different network levels. To arrive at the LDNO charge, the charge payable by the end customer (the "all the way" charge) is discounted based on the network levels *not* used by the LDNO, ie those below or downstream of where the LDNO connects to the DNO.

2.3. Under the EDCM, this method is expanded to become the extended Method M model, to calculate additional discounts for the EHV tiers of the network. Additionally, the DNOs also propose that LDNO discounts be determined not only on the basis of the LDNO's and customer's level of connection, but also on the basis of the network levels provided by the DNO above or upstream of the LDNO's point of connection.[14] This means that a further discount is provided based on the network levels not used by the DNO to service the LDNO (and in turn the end customer). This creates 15 different LDNO discounts, rather than the five (or three in Scotland) that would result if the discount only depended on the LDNO's (and customer's) point of connection.

Consultation and responses

2.4. In our consultation[15] we expressed some concerns with this proposal. We said that varying LDNO discounts on the basis of the upstream assets provided by the DNO may be inappropriate given that the end charges to CDCM customers are fixed and do not vary by the nature of the upstream DNO network. That is, the all the way charges are the same regardless of the assets provided by the DNO (or for that

[10] The Authority is given the power to apply conditions under SLC 50A.21.
[11] SLC 50A.22.
[12] See page 71-72 of our consultation for further explanation of how charges are calculated.
[13] That is, where a CDCM-connected LDNO is servicing a CDCM customer.
[14] See example on paragraph 5.20 of page 76 of our consultation.
[15] Issue 15: number of discount tariffs (connection types) applicable to LDNOs, page 76

matter, the LDNO). We also noted the proposal creates a practical issue in that it creates the need for a larger number of LDNO tariffs.

2.5. We stated that our initial view was to make it a condition of our approval of the EDCM that the methodology be revised so that LDNO discounts for a given category of CDCM customers only vary with the point of connection.

2.6. We received mixed responses to our question[16] as to whether varying LDNO discounts only with the point of connection would better achieve a balance between appropriately reflecting upstream and downstream costs. Both LDNOs that responded, along with a demand customer and a supplier, agreed that discounts should vary only with the point of connection. While most DNOs supported their submission, one thought that the issue should be reconsidered by the DNOs. Another made the observation that the DNOs' proposal could incentivise LDNOs to connect sites that attract bigger discounts, ie those where there are "missing" levels in the upstream DNO network.

Our view

2.7. We think that varying Method M discounts based on the network levels provided by the DNO undermines the validity of the model to generate appropriate discounts as the CDCM charges are fixed within a DNO's region.[17] The margins that are calculated under network configurations that include all network levels reflect the average cost of the DNO's actual network. This means that the various network configurations are already taken into account on average. We do not think that a further discount on top of this is consistent with the Method M approach.

2.8. The DNOs' argument for using 15 discount categories is that the resulting charges to LDNOs are more cost reflective. However, we think that using five discount categories (that is, when LDNO discounts do not vary with the DNO's assets above the point of connection) ensures charges are *on average* cost reflective. We recognise that in some situations the LDNO charge could arguably be "too high" while in others it could arguably be "too low". But the charge would be cost reflective on an average basis, consistent with the CDCM end-user charges.

2.9. The issue arises because of the different approach of the EDCM (site-specific charges) and the CDCM (average charges), which are somewhat in conflict. We think that it is artificial to try to apply a site-specific approach to the calculation of CDCM discounts in circumstances where that discount applies to a charge calculated to

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[16] Question 5.3
[17] We consider that it would be inappropriate to vary LDNOs' discounts based on the network levels above the point of connection without also varying CDCM charges based on the network levels used, ie providing a discount to all CDCM customers located in areas where less assets are used to serve customers. We think that doing so would be inconsistent with the CDCM that applies average rather than site-specific charges and that failing to recognise the effect of this averaging approach would undermine the logic of applying a discount method.

reflect costs on an average basis, rather than by site. We note that the extent of the site-specificity employed under the DNOs' proposal is simply whether the upstream network is missing assets, not the more fundamental assessment of locational charges and asset costs that is used to generate other EDCM charges. This means that applying a less site-specific approach in this respect does not undermine the ability of the EDCM to reflect appropriately the relevant costs.

2.10. We think that giving LDNOs a further discount where upstream network levels do not exist is not appropriate. The LDNO is not providing any more assets or service than it does when those network levels are present: the additional discount may represent a windfall gain for the LDNO at the expense of the DNO's other customers. This additional margin is effectively transferred from other customers who must meet the shortfall in allowed revenue that is not recovered from the LDNO.[18] We do not consider it necessary or desirable to provide a margin to LDNOs that would be in excess of the costs of an as efficient competitor.

2.11. We consider that the DNOs' proposal has the potential to distort competition between LDNOs and DNOs. DNOs' CDCM charges are based on the average cost of servicing their end customers. Introducing a form of site-specific charges for LDNOs would mean that LDNO and DNO CDCM charges are calculated on a different basis. The additional margin received by the LDNO could provide an unfair advantage of the LDNO over the DNO. As noted in the paragraph above, the margin available would be in excess of the costs of an equally efficient competitor to the DNO. This means that LDNOs could offer a substantially lower price for a new development than could a DNO without this reflecting any efficiency advantage and/or benefitting customers generally.

The condition

2.12. After taking into account these issues, we have decided to place a condition on the DNOs to reduce the number of customer categories for LDNO discounts so that discounts do not vary with the network levels the DNO provides above the point of connection. This means that in England and Wales the number of customer categories for LDNO discount would reduce from 15 to five and in Scotland it would reduce to three. This condition must be met by **30 November 2011**.

2.13. We think that, taking into account our statutory duties and obligations, the condition helps to ensure the EDCM for import charges, in the round, better achieves the Relevant Objectives set out in the licence. Our reasoning particularly relates to the second and third Relevant Objectives, as well as our principle objective of protecting the interests of existing and future consumers.

2.14. We consider this condition would better achieve the second Relevant Objective, that compliance with the "EDCM facilitates competition in the generation

[18] There is no corresponding windfall gain to DNOs if the number of categories is reduced, as DNOs total allowed revenue is not affected by the charging methodology.

and supply of electricity and will not restrict, distort, or prevent competition in the transmission or distribution of electricity", for the following reasons:

- It ensures that CDCM charges and their associated discounts are on the same basis for DNOs and LDNOs, to prevent an artificial advantage being created for any particular party.
- It prevents additional revenue being received by the LDNO where it is not incurring any additional costs or demonstrating greater efficiency. This ensures that the LDNO does not have an unearned competitive advantage over the DNO.
- It would reduce the potential for competition to be distorted through LDNOs favouring areas with the least amount of upstream assets.
- The lower number of discount categories would result in a small reduction in complexity, thereby furthering the transparency and simplicity of these charges, which can be expected to increase competitive pressures.

2.15. We consider that the condition ensures that the EDCM would better achieve the third Relevant Objective, "that compliance with the EDCM 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 licensee in its Distribution Business". The discounts are provided based on an average charging model using an average discount model. While an argument is being made that varying the discounts based on the upstream assets of the DNO is *more* cost reflective, we think it is neither appropriate nor workable to introduce this granularity to an approach that works from a total charge calculated under an average cost model.

2.16. For the purposes of the charging methodology, the DNO's allowed revenue is fixed by the price control. This means that any "additional" discount given to LDNOs must be recovered from the DNO's other customers. We do not consider this transfer appropriate, as it does not reflect any additional assets or services provided by the LDNO.

Condition 2: to modify the method of sense checking branch incremental costs in LRIC

2.17. The EDCM includes a "locational" element of the charge, calculated using either the Forward Cost Pricing (FCP) or Long Run Incremental Cost (LRIC) methods. In the case of LRIC, the EDCM applies a cap to this component of the charge. The cap is set so that the total recovery of LRIC charges on each branch[19] does not exceed the annuitised reinforcement cost of the branch.

[19] The EDCM submission often uses the term "branch" instead of "asset", in particular in the context of power flow analysis. The term "branch" is defined in Appendices 2(a) and 2(b) of the EDCM submission. In essence, a branch is a continuum of assets without a tee-off point along it, so that the active power flowing into one end equals the active power flowing out of

Consultation and responses

2.18. In our consultation[20] we raised two concerns about the proposed sense checking (capping) mechanism and said that subject to responses, we would consider placing a condition to amend the method used. The concerns we raised were that:

- The mechanism compares net recovery to the reinforcement cost of the branch rather than separately comparing the sum of charges and the sum of credits to the branch reinforcement cost.
- The mechanism compares the sum of recovery from demand and generation charges together rather than comparing recovery from demand and generation separately to the reinforcement cost of the branch.

2.19. Respondents to our consultation[21] agreed that charges and credits should be separately compared to the reinforcement cost of the branch. The majority of respondents also agreed on the second concern, although two respondents argued that recovery from demand and generation should not be separately compared to the branch reinforcement cost, but rather total recovery from both demand and generation should be used.

2.20. We engaged with the DNOs to understand the impact on customer charges of such amendments. We found that for a very small number of demand customers this amendment can result in material increases (relative to the pre-condition method), but for the vast majority this was not the case.

The condition

2.21. Given the responses and further consideration of the issues, our decision is to place a condition on the DNOs to amend the sense checking mechanism such that positive cost recovery and negative recovery are separately assessed against the reinforcement cost of the branch. This condition must be met by **30 November 2011**.

2.22. We think that our condition ensures that the EDCM would better achieve the Relevant Objectives, in particular the third Relevant Objective "that compliance with the EDCM 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 licensee in its Distribution Business".

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the other end of the branch less any losses within the branch.

[20] Issue 20: sense checking of branch incremental costs in LRIC, page 86.

[21] Question 6.4.

2.23. It would more accurately reflect the costs of future reinforcement by ensuring that total charges paid in respect of bringing forward the expected time of reinforcement of a branch do not exceed the (annuitised) reinforcement cost of the branch. Similarly, the condition will ensure that total credits paid for deferring the expected time of reinforcement of an asset do not exceed the (annuitised) reinforcement cost of the asset.

2.24. After further investigation, we are not yet sure that there is the same clear rationale behind splitting demand and generation. For example, the method we suggested in our consultation would not take into account the relative probability of either generation or demand led reinforcement occurring. However, further investigation may result in a clearer rationale and in light of the broadly supportive consultation responses, we encourage the DNOs and other parties to continue to consider this issue and if necessary bring forward a proposal under open governance.

Specific issue of asymmetric scaling

2.25. One respondent identified that such separation can lead to asymmetric scaling factors across charges and credits in respect of the same branch. This, in turn, would lead to asymmetric charges for the branch (as the credit rate would not be the negative of the charge rate). However, based on current evidence we think it is more important that charges (and credits) do not exceed the annuitised costs of reinforcements that are being brought forward (or deferred) than preserving a strict symmetry between charges and credits. We are not convinced that addressing the issue by equalising the scaling factors will result in a better mechanism but we encourage DNOs (and other parties) to consider this under open governance.

Condition 3: to review the method for calculating network use factors

2.26. A network use factor (NUF) is the value of assets, at a given network level, used for the supply of a unit of power (kW) to a specific EDCM demand customer, relative to the average value of assets at the same network level used for the supply of a unit of power to CDCM customers. For example, a NUF of two would indicate that the customer uses twice as many assets to serve it as the average CDCM customer.

2.27. NUFs play an important role in the determination of charges under the EDCM, as they are a key input into the calculation of customers' notional asset values (NAV). The customer's NAV is compared against the DNO's total NAV to determine their share of certain DNO costs, ie it is used as a cost driver for the allocation of what are deemed to be asset related costs. These costs include some direct costs and network rates and a proportion of the residual revenue. They comprise on average 44 per cent of customers' charges.

Consultation and responses

2.28. In our consultation[22] we identified two issues related to the calculation of NUFs. The first was that NUFs are calculated based on asset usage under an intact network without consideration of asset usage under contingency events. The second was that the full value of the asset is allocated amongst the customers that use it at maximum demand, even if there is unused capacity ("spare capacity") on the asset.

2.29. We said that on balance we consider that calculating NUFs on the basis of power flows under an intact network was a reasonable and pragmatic approach. This is because the method is applied in a consistent manner across all the nodes of the EHV network (EDCM nodes and CDCM nodes at primary substations) which should mitigate the potential for less cost reflective NUF values.

2.30. On the issue of spare capacity, we said that it might be appropriate to recover the associated costs from all network users through the scaling process and that subject to responses we would consider placing a condition on our approval. We also noted that there are two mitigating measures to the issue of spare capacity. The first is the cap and collar that is applied to the NUFs. The second is the fact that spare capacity will tend to inflate not only the value of assets deemed to be used by an EDCM customer but also the value of assets deemed to be used for the supply of CDCM customers. As we noted, because the former is divided by the latter, the effect of spare capacity on the value of NUFs is ambiguous.

2.31. Respondents to our consultation[23] generally agreed that costs associated with spare capacity should not necessarily be borne by the user of the asset. At the same time, a number of respondents suggested that this issue may require further work in order to understand the circumstances in which it arises and the impact on customers. For example, where assets are available only in certain capacities (ie they are indivisible so there is some built in natural spare capacity), it may not be appropriate for the difference between the customer's capacity and the rated capacity of the asset to be recovered from other users.

2.32. Following our consultation, the DNOs re-convened their working groups to consider possible ways to address our concern over the treatment of spare capacity. The DNOs developed a possible alternative method to calculate the NUFs. The alternative method estimates the proportion of spare capacity on every asset and uses this proportion to reduce the asset's modern equivalent asset value used for the calculation of NUFs. The alternative method has a material impact on customer charges.

[22] Issue 5: calculation of network use factors, page 45.
[23] Question 3.5.

The condition

2.33. The condition we are placing in relation to this issue requires the DNOs to conduct further investigations into the issue, including an open consultation with relevant stakeholders and to provide a report to us on the issue by **1 June 2012**. The report must:

- Examine the circumstances in which it may or may not be appropriate to socialise spare capacity costs and the different options which could be used to do this.
- Assess the materiality of the impact on customers charges' and whether these can be justified.
- Provide a well reasoned recommendation to change the methodology or a well reasoned report saying why no change is necessary.

2.34. Should we accept a recommendation that requires a change to the methodology we expect the DNOs to bring forward this change under the open governance process. A strong supporting argument must be presented if the recommendation is that the existing method should remain unchanged.

2.35. We consider that our condition will ensure that the EDCM better achieves the Relevant Objectives, in particular the third Relevant Objective "that compliance with the EDCM 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 licensee in its Distribution Business". We think that the proposed site-specific method of allocating certain costs to demand customers should reflect those costs in the most appropriate way. This condition will ensure that a proper investigation and assessment of this issue is made, and if warranted, a change can be brought forward to improve the methodology.

2.36. We note that this issue may have interactions with the NUFs used for the calculation of import charges in generation-dominated mixed sites (issue 12 in our consultation). NUFs to generation-dominated mixed sites are currently set to a default level equal to the collar of all NUFs at every network level. To the extent that a proposed modification to the DCUSA seeks to revise the calculation of NUFs for demand customers that are not part of a generation-dominated mixed site we expect the DNOs to consider whether the use of default NUFs in generation-dominated sites is still appropriate.

2.37. This condition is to be met after the introduction of EDCM charges for demand customers on 1 April 2012.[24] This timeframe will enable DNOs time to investigate and consult on the issue, in light its complexity and the likelihood of material impacts on some customers.

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[24] We would not envisage charges being calculated under any alternative method of calculating NUFs to be put in place until 1 April 2013 at the earliest.

2.38. This means that the existing method of calculating NUFs would apply initially and this would only be changed if following further analysis and consultation an improved method can be brought forward. We are comfortable with the existing method being used because we consider it an appropriate way of reflecting costs incurred by individual customers and note the existing mitigation measures referred to in paragraph 2.30 above. We note that the DNOs have the option to bring forward derogation requests if they think that the current methodology and its assumptions is not appropriate for some of their customers.

3. Customer assistance measures

3.1. The introduction of the EDCM for import charges will result in a significant rebalancing of charges across EHV customers. While around three quarters of EDCM demand customers will see either no change or a reduction in their use of system charge, some customers will see substantial increases in percentage and/or pound terms.

3.2. We think it is reasonable that DNOs assist these customers in particular with managing the transition to the new charging methodology. We also think that DNOs should undertake work to investigate and if necessary propose modifications to the methodology to help customers manage their change on an ongoing basis.

3.3. In this chapter, we set out a number of expectations on DNOs. While these do not form conditions of our approval, we will be monitoring the steps that the DNOs take in these areas and welcome feedback from stakeholders on the progress made. If there is not sufficient progress by the DNOs, we will consider whether to take further action through their licences to ensure customers' needs are appropriately managed.

Customer measure 1: to provide assistance to customers on managing their charge

3.4. We stated in our consultation[25] that we were considering whether to require the DNOs to develop a package of measures to help customers manage their charges under the EDCM. We suggested that part of this package could include advising customers on what they can do to manage their charge.

3.5. While we did not ask a specific question on this part of the proposed package of measures we think that, based on our analysis and stakeholder feedback, the increases experienced by some customers justify the DNOs providing some form of assistance. We have also taken into account comments made by some suppliers, particularly at our workshops, cautioning that measures recommended by the DNO may not always necessarily be consistent with supply contracts, and thus may not necessarily result in the customer realising the savings estimated by the DNO.

3.6. After taking into account this feedback, we have decided to set out an expectation on DNOs to contact the most affected customers to provide them with advice on how they might reduce their charge. DNOs may wish to apply a threshold to which customers they contact, eg if their charge is increasing by a certain percentage, or make a qualitative assessment of the most affected. We also suggest the DNOs offer this assistance to any other customer that requests it.

[25] Page 23.

3.7. Each DNO should provide a written explanation to each particular customer that explains what they can do to reduce their charge. For example, this could include reducing "super red"[26] consumption, entering into a demand side management agreement, or reducing maximum import capacity.

3.8. Where possible, the DNOs should provide an estimate of the likely savings of each measure.[27] It is for each DNO to decide how they present this information, eg simply in writing or in a spreadsheet. We note that some DNOs have been experimenting with a web based tool which would allow customers to vary their own input data to see the impact on their charge, and this may prove particularly useful for customers.

3.9. The estimated charges should clearly be presented as indicative. The information provided by the DNO should advise the customer that they should assess whether their own circumstances allow them to take such measures. This includes circumstances related to their own business, their electricity supply (or other) contracts or a technical reason that might prevent them from realising the charge reduction. To this end, we also encourage customers, suppliers and DNOs to interact, so that the customer can make a decision after understanding the full effect of any change to their behaviour.

Customer measure 2: to formalise the arrangements for demand side management agreements

3.10. A demand side management (DSM) agreement is one of the methods by which customers may be able to reduce their charge. This works by the customer agreeing to have their capacity restrained at certain times (eg during peak or "super red") which may help to defer reinforcement works. In recognition of this, the customer may receive a lower charge. Under the EDCM, customers with DSM agreements have the locational element of their charge calculated based on the DSM-restricted capacity rather than the agreed maximum import capacity.[28]

3.11. We noted in our consultation,[29] however, the lack of clarity on the terms available to customers in entering such agreements. We asked the DNOs to clarify:

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[26] The super-red time band is a period when the network is highly loaded and when the annual simultaneous maximum demand is likely to occur. We set these out in Table 4.4 on page 63 of our consultation.
[27] We recognise that under the DCUSA, the DNO may be prevented from disclosing charges to some end customers, and thus may be unable to provide estimates in their letter. DNOs should take all reasonable steps to seek the permission of the supplier to provide the estimates directly to the customer or to disclose them as part of any tripartite discussion. If permission is not forthcoming, then the DNO should provide the estimates to the supplier.
[28] See page 20 of the DNO's EDCM report of 1 April 2010, available at http://2010.energynetworks.org/edcm-file-storage/7-edcm-deliverables/1-edcm-submission-1st-april-2011/
[29] Issue 18: demand/generation side management, page 82.

- Whether any customer can enter a DSM agreement with the DNO, provided the customer agrees to have interruptible capacity subject to such terms as defined by the DNO.
- Whether the DNO can refuse to enter such agreements. We also expressed a view that if charging arrangements under these agreements are appropriately reflective of costs, they should be available to every customer.

3.12. We asked stakeholders[30] whether they agreed with our view that the DSM arrangements were appropriate and whether agreements should be available to all customers. Three demand customers were generally supportive of both the arrangements and the proposition that it should be available to all customers. Some suppliers thought it should be available to all customers, although some were concerned about how DSM agreements would work with the supply contract arrangements.

3.13. DNOs that responded on the issue were broadly supportive of the arrangements for DSM agreements. One wanted to make clear that they were not an incentive but were meant to reflect the avoidance of costs with another echoing this sentiment in arguing they should only be available where the benefits can be established. One LDNO wanted more information on how it would work for LDNOs.

3.14. The Common Methodology Group (CMG) advised that the Energy Networks Association's (ENA) Capacity Management Working Group is looking at this issue. We understand that this group is currently considering the issue in the context of broader discussions around capacity utilisation, but have not yet made any findings. We note that this working group is open to all stakeholders and we encourage interested parties to become involved.

3.15. We expect the DNOs to clarify these arrangements in a timely fashion. Initially, we expect customers will benefit from the DNOs simply outlining their individual policy on DSM agreements. This will enable them to consider negotiating a DSM agreement well in advance of the commencement of charges on 1 April 2012. We suggest the DNOs include the following:

- Advise whether a DSM agreement will be available to any customer that requests it and if not what the proposed eligibility requirements would be (with the reasons for imposing such a requirements).
- Outline the process that customers should go through if they want to explore the possibility of a DSM agreement, including the provision of indicative timeframes and estimated savings and information on the amount of capacity they would require to be interruptible and at what times.
- How DSM agreements apply in the case of LDNOs.
- Set out any other issues with DSM agreements that they think are of relevance to customers.

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[30] Question 6.2.

3.16. We then suggest the DNOs assess whether to develop a common approach for DSM agreements, to complement the common approach of the EDCM. This might also consider how DSM agreements apply in the case of LDNOs, if there are no current arrangements found to be in place.

3.17. We also suggest that DNOs give early consideration to whether the current and/or proposed contractual arrangements for DSM agreements also apply to generation side management (GSM) agreements. This will provide the opportunity for GSM arrangements to be clarified well in advance of the commencement of EDCM generator charging (should we approve it) from April 2013 (or possibly later).

Customer measure 3: to assess measures to reduce volatility

3.18. In our consultation,[31] we recognised that the new charging methodologies such as the EDCM contain some inherent volatility. We noted that demand customers, suppliers and generators have expressed concerns about this issue, and have supported the development of mechanisms to mitigate volatility. We outlined the steps taken so far:

- The DNOs' requirement to publish long term tariff scenarios on an annual basis.
- Expectation that DNOs will follow up and address residual issues around volatility, transparency and predictability of charges through open governance.
- Establishment by the DNOs of Workstream C (WSC) – Longer Term Charging Products to look at these issues.
- The DNOs' report on the potential impact of volatility in their EDCM submission.
- WSC agreement that DNOs will consider carrying out a more comprehensive analysis based on customer feedback, including possible mitigation measures.

3.19. We stated in the consultation that we were considering placing a requirement on the DNOs to mitigate some of the inherent volatility within the EDCM and to allow customers the option to manage their charge volatility through access to a long term product with a more stable (but not necessarily fixed) charge.

3.20. The response to our request for stakeholder views[32] was strong, with almost all stakeholders commenting on the issue. The majority of the responses, particularly from demand customers, suppliers and generators, were either concerned or very concerned about volatility and/or expressed support for measures to mitigate volatility. However, some, including some DNOs and generators expressed concern that measures to reduce volatility could also reduce the cost reflectivity of the charges. One DNO did not support measures to reduce volatility.

3.21. At the workshops we held as part of the consultation, some stakeholders raised the further issue that allowing some customers to fix their charge, or elements

[31] Issue 21: volatility, page 88.
[32] Question 6.4 (2nd).

thereof, could actually increase volatility for other customers. This is due to a fixed amount of revenue being recovered from EDCM customers. The point was also made that there may be other parties better able to manage this risk, such as suppliers.

3.22. WSC issued a consultation on long term products on 19 August 2011.[33] We also expect the DNOs to consider and consult on whether some input data (eg network use factors) might be smoothed or averaged to minimise volatility *for all customers* or whether there are other aspects of the methodology that could also help to reduce the volatility of charges, particularly where that volatility arises from matters outside customers' control.

3.23. Should these processes find that changes are appropriate, we expect the DNOs to propose necessary modifications under the open governance process. Ideally, any measures would be put in place prior to the production of 2013-14 indicative charges – the first change in charge under the EDCM.

3.24. The issue described above refers to volatility which results from the way the EDCM allocates the total allowed revenue between customers, ie volatility *internal* to the methodology. Another source of volatility is external, that is, the year on year change in the allowed revenue itself. We are continuing to look at whether the price control arrangements can be improved with respect to this type of volatility.

Customer measure 4: to provide visibility of cost signals

3.25. A number of respondents to the consultation argued that there should be more visibility of the cost signals given by the EDCM. This would provide a clear signal about where the most cost effective place is to locate. While we note that most of these arguments came from generators, we think that current and future demand customers would also benefit. Greater visibility of cost signals will help customers to reduce their charge as well as encourage them to connect in areas which are likely to result in a lower charge by making use of spare network capacity.

3.26. Over recent years, we have introduced a number of measures that aim to provide better technical and commercial information for customers wishing to connect to and use the distribution networks. This includes the Long-Term Development Statements[34] and the Distributed Generation: Connections Guide and Information Strategy.[35]

3.27. We think that making information available for all customers on EDCM prices would strongly complement these initiatives and we encourage the DNOs to do so. Going forward, we would also expect the DNOs to consider how these tools could be

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[33] Available at: http://energynetworks.squarespace.com/edcm-file-storage/5-cmg-and-its-workstreams-a-b-and-c/02-workstream-c-longer-term-charging-products/
[34] SLC 25.
[35] SLC 25A.

developed in a coherent way to further enhance their value to customers (and ultimately for the benefit of the networks themselves).

3.28. In collectively developing mechanisms that aim to provide greater visibility of EDCM pricing signals, we think the DNOs should take into account the following criteria:

- The best way of presenting the information so that it is accessible to customers, eg through providing maps and/or lists of locations or areas showing charges.
- The need for information to be presented in a consistent way across DNOs to aid customers considering locations across a number of DNO areas; and for this consistency to be maintained over time.
- Which components of the charge should be shown, given that:
    - it may not be accurate to include sole use assets where different customers will have different needs; and
    - it may not be sufficient to show only the locational element of the charge, given that a customers' final charge is significantly influenced by the assets that it uses.
- The need to sufficiently anonymise the data so as to protect customers' confidentiality, for example it may be best to show a £/kVA and £/kWh, which would also aid customers calculation of their likely charge, and/or in bands, rather than giving the specific charge.
- The level of detail shown on the map, ie whether specific sites should be shown based on existing customers, or indicative charges should be created based on specific points to create coloured areas (eg per network group in the case of FCP).
- When the maps should first be created and when they should be updated.

3.29. This list is not exhaustive and there are likely to be other factors to take into account. We also encourage the DNOs to open up the forum in which they develop these mechanisms, to allow any interested stakeholder input into the development process. We expect this work to be progressed as a priority.

4. Areas for potential further development

4.1. A key component of the structure of charges project is to enable improvements to be made to the methodologies through open governance. Following our analysis of the EDCM and the responses to our consultation, we have identified four areas which the DNOs and other parties should give consideration to addressing through this process.

4.2. We also note that the DNOs have a licence obligation[36] to review the methodology at least once every year to ensure the EDCM continues to achieve the Relevant Objectives and bring forward appropriate modifications as necessary.

Development issue 1: consideration of peak time reactive flows

4.3. The EDCM uses a combination of the customer's maximum import capacity and their historical capacity used at peak, in order to allocate the customer a share of the DNO's indirect costs and 20 per cent of the residual revenue. The calculation used for the share is the sum of 50 per cent of the customers maximum import capacity (kVA) and their historical capacity at system peak (kW).

4.4. We noted in our consultation document[37] that using kW (which excludes reactive power) rather than kVA (which adjusts for reactive power) to calculate the capacity at peak meant that the calculation only partly took reactive power into account. We invited stakeholders' comments on our view that peak time capacity *should* incorporate reactive power flows, so that the full cost implication of the customer's active power consumption during system peak is taken into account.

4.5. Nine stakeholders responded to this question.[38] Six agreed with our view that it would be more cost reflective to fully account for reactive power (although one of them, a demand customer, thought making the change was probably not worth the additional complexity). An LDNO, disagreed with our view on the basis that reactive power does not influence indirect costs. One DNO did not express a view, simply noting that the calculation partially takes into account reactive power. The CMG advised it was currently carrying out analysis of the issue. It later reported that the DNOs have looked at this issue and noted that customers with poor power factors would be affected by the change.

4.6. As we stated in our consultation, we are broadly comfortable with the DNOs' approach to allocating indirect costs and 20 per cent of the original. Although we expressed a view that peak time capacity *should* incorporate reactive power flows,

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[36] SLC 13B.5.
[37] Issue 3: allocation of indirects and a portion of the residual based on capacity, page 39.
[38] Question 3.3.

we did not specifically flag that the imposition of a condition in our consultation for this issue and continue to believe that this issue is not significant enough to warrant a condition. We note that the DNOs or any other DCUSA party could, under the open governance arrangements for the EDCM, bring forward the issue of how indirect costs are allocated.

Development issue 2: LDNO discount on 20 per cent of residual revenue

4.7. This issue relates to the calculation of location specific charges for LDNOs that have EDCM end customers connected to their network.[39] Where the LDNO has declared a "boundary equivalent" capacity for their EDCM customer, the LDNO pays the DNO the full EDCM charge, less a 50 per cent discount on the allocated indirect costs.

4.8. This 50 per cent discount is intended to reflect that LDNOs will have indirect costs of their own and could potentially displace some of the DNO's indirect costs. In our consultation,[40] we set out our initial thoughts that a similar logic could be applied to other capacity-based charges. These charges also included costs that could be incurred by the LDNO in servicing their customer. In the case of demand, this would apply to the 20 per cent of residual revenue for demand customers.

4.9. Eight parties responded to this question[41], representing a mix of stakeholders. Six supported applying this discount, although two (the CMG and an LDNO) suggested that further analysis was required. One DNO did not state a position, but suggested DNOs reconsider the issue. Another thought the current proposals were reasonable for estimating discounts and that there is some scope to further examine the issue, although in doing so, there should be recognition of the differences in indirect costs that DNOs and LDNOs face.

4.10. CMG highlighted there were practical difficulties in applying this discount in the case of negative scaling, ie where the residual revenue is negative and customers' charges are scaled down. This would result in a negative discount to the LDNO meaning the charge would be increased rather than discounted.

4.11. While we set out our initial view to apply a condition to fix this issue, we do not think it appropriate to do so in light of the issue around negative discounts. We think that this issue would be better resolved under the open governance arrangements, where the implications can be fully considered. The DNOs, LDNOs or any other DCUSA party could bring forward this specific issue and/or the issue of the allocation of indirect costs between DNOs and LDNOs more broadly.

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[39] This issue is discussed on page 75 of our EDCM consultation.
[40] Issue 14: components of location specific charge paid by the LDNO, page 75.
[41] Question 5.2.

Development issue 3: customer categories – consideration of assets below the voltage of connection

4.12. In discussing the issue of customer categories in our consultation,[42] we noted that when allocating asset-related costs, the EDCM does not take into account customers' usage of assets below the voltage of connection. This is because while network use factors (NUFs) below the voltage of connection may exist, these are "ignored" based on the customer's category.

4.13. We set out our thoughts that in a site-specific method of allocating costs, all DNO assets used by the customer to service them should be taken into account, especially if there were significant flows from below (we thought an example would be when a customer is supplied through distributed generation below its level). We asked the DNOs to explain why the EDCM does not take them into account.

4.14. Responses to the question on this issue[43] were mixed. Approximately half did not believe assets below the voltage of connection should be taken into account, with some arguing it was not appropriate or cost reflective. Of the other respondents, one DNO thought it might be appropriate in some circumstances but would have a large impact on customer charges. A demand customer was unsure of the materiality of the issue and another respondent did not think the issue would arise in general with one possible exception. One DNO did agree in principle, but did not believe the benefits would outweigh the additional work required.

4.15. CMG have advised that this issue would impact a small number of customers. We understand that almost all NUFs below the voltage of connection are non-material and thus there would be only a very small impact on charges. From discussions with the DNOs they also noted practical difficulties with taking NUFs below the voltage of connection for those customers at the lowest level in the EDCM (ie connected at high voltage and metered at a primary substation), for which NUFs are currently not calculated.[44] We also understand that at this time, flows from DG are not necessarily taken into account for this type of analysis.

4.16. While we think that taking into account these flows would further increase the site-specific cost reflectivity of the EDCM, we think that the issue is not significant enough to warrant action at this time. We expect the DNOs to keep this issue under review, monitoring whether upwards flows are becoming material (eg if DG were taken into account for these purposes), and giving consideration to the issue of calculating NUFs for levels covered by the CDCM. The DNOs (or another DCUSA) party could propose a modification if and when necessary.

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[42] Issue 7: customer categories, page 50.
[43] Question 3.6.
[44] Technically this applies to all customers, however we understand the likelihood that a customer above this level would have material NUFs at levels covered by the CDCM is very low.

Development issue 4: capping of LDNO discounts at 100 per cent

4.17. The EDCM relies on the extended Method M model to calculate charges in respect of CDCM customers of LDNOs that are subject to the EDCM. When a DNO's incentive revenue is negative, the discount percentage resulting from the extended Method M model could exceed 100 per cent. This means that under such a situation DNOs will have to pay a 'use of system' credit to LDNOs in respect of demand customers.

4.18. The EDCM as submitted to us proposed to cap the portion of charge available for discounting at 100 per cent of the charge in order to avoid such situations.

4.19. In our consultation[45] we said that in circumstances where without capping the discounts could be greater than 100 per cent, it may be appropriate for DNOs to pay LDNOs some kind of credit, particularly where the implied discount is significantly in excess of 100 per cent. This is because the incentive revenues are not clearly related to the cost of running the DNO network and therefore the impact of capping may be that the DNOs total costs are not fully considered for the LDNO discount.

4.20. LDNOs that responded to our consultation[46] argued that applying the cap may prevent the LDNO from recovering an appropriate margin. Other respondents, mainly DNOs, argue that such a cap is appropriate and that its absence could provide a perverse incentive for increased energy consumption and network losses on the LDNO's network.

4.21. We note that we are not aware of any LDNO that would qualify for a discount greater than 100 per cent currently. We also do not think that it is likely to be an issue in the near future because no DNO has strongly negative incentive revenue and because the LDNO network would have to be connected very high up a DNO's network (possibly directly to the GSP) to qualify.

4.22. On this basis, we are not making the removal of the 100 per cent cap a condition of approval of the EDCM. We consider that this matter should be kept under review and if necessary a modification should be proposed under the open governance process.

[45] Issue 16: capping discount percentages to 100 per cent, page 76.
[46] Question 5.4.

Appendices

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Appendix 1 – Consultation questions and responses

1.1. In our May 2011 consultation document (Electricity distribution charging methodologies: distribution network operators' (DNOs') proposals for the higher voltages, Reference number: 67/11) we sought the views of respondents in relation to any of the issues set out in the document as well on a number of specific questions.

Consultation questions

Chapter 2

Question 2.1: What are your views on the key issues with the methodology we have highlighted? Are there any other issues or concerns with the methodology as a whole that we should consider?
Question 2.2: Should we approve the methodology, do you agree with our proposal to implement it in full from 1 April 2012? If not, why is phasing-in charges or delaying implementation appropriate?
[Note: we would appreciate early responses to this question by 24 June 2011 if possible – although we will still consider responses submitted after]

Chapter 3

Question 3.1: Do you agree with our assessment that the approach for the revenue target is reasonable?
Question 3.2: Do you think the principle the maximum import capacity is a cost driver at the voltage of connection is reasonable for charging purposes?
Question 3.3: Do you agree with our view that reactive power flows should be incorporated as part of the capacity that attracts indirect costs and 20 per cent of the residual?
Question 3.4: Is it appropriate to consider the specific assets the customer uses for the calculation of the customer's charge, or would it be more appropriate to consider only the voltage levels the customer uses for the calculation of its charges?
Question 3.5: Do you think that the 'spare capacity' issue we identify should be addressed?
Question 3.6: Do you think notional asset values should take into account assets below the customer's voltage of connection?
Question 3.7: Are there any other demand specific issues that you think we should consider as part of our decision?

Chapter 4

Question 4.1: Do you agree with our proposal to modify the generation revenue target in order to avoid double charging for operations and maintenance costs on

sole use assets? This issue aside, do you agree with our view that the approach to calculating a generation revenue target is reasonable?
Question 4.2: Do you agree with our assessment that the approach to scaling is reasonable?
Question 4.3: Do you think it is appropriate for only units exported by non-intermittent generators during the super-red time band to be eligible for credits?
Question 4.4: Do you agree with our proposal that intermittent DG should be eligible for credits as they are deemed to provide network benefits under ER P2/6? If they do become eligible for credits, should the credits only relate to units exported during the super-red time band or is a single credit rate to all units exported more appropriate?
Question 4.5: On import charges for generation dominated mixed import-export:

- Do you agree with our suggested alternative to using the collar of the network use factor for the calculation of the import tariff?
- Do you think that the methodology is appropriate for demand customers connected to generation dominated assets?

Question 4.6: Are there any other generation specific issues that you think we should consider as part of our decision?

Chapter 5

Question 5.1: Do you agree when calculating LDNO charges that DNO costs upstream and downstream of the point of connection should be considered?
Question 5.2: Do you think that DNOs should provide LDNOs with a discount on all non-asset based charges?
Question 5.3: Do you think that varying LDNO discounts only with the point of connection will better achieve a balance between reflecting upstream and downstream costs?
Question 5.4: Do you agree that it may be appropriate in some circumstances for the DNO to pay LDNOs use of system credits?

Chapter 6

Question 6.1: Do you think sole use assets should attract scaling 'costs' to the same extent as shared assets? Does the charging rate on sole use assets seem reasonable given the nature of these assets?
Question 6.2: Do you agree with our view that the arrangements for demand and generation side management agreements are appropriate? Do you think such agreements should be available to all customers?
Question 6.3: Do you agree with our assessment that an explicit reactive power charge is not appropriate?
Question 6.4: On the proposal for sense checking branch incremental costs in LRIC:

- Do you agree with our view that positive cost recovery (ie charges) and negative cost recovery (ie credits) should be considered separately?
- Do you consider that recovery from demand customers and recovery from generation customers should be considered separately?

Question 6.4 [sic]: Do you think the EDCM should include a mechanism to mitigate the potential volatility from network use factors? We welcome views on measures to mitigate volatility and help customers manage volatility.

Consultation responses

1.2. We received responses to our consultation from 31 entities, three of which were marked confidential. We have published the non-confidential responses on our website.[47] Copies of non-confidential responses are also available from our library.

List of non-confidential respondents

List	Name	List	Name
1	BOC	15	Highlands and Islands
2	British Gas/Centrica	16	Mathematical and Computer Modelling
3	CE Electric	17	Renewable Energy Association
4	Centrica	18	RWE npower
5	CHPA	19	Scottish & Southern Energy
6	DONG Energy	20	Scottish Renewables
7	EDF	21	ScottishPower Energy Networks
8	ENA CMG	22	ScottishPower Energy Retail
9	ENW	23	ScottishPower Renewables
10	EPRL-CLP	24	smartestenergy
11	ESB International	25	Tata Steel
12	ESP Electricity	26	UK Power Networks
13	Falck Renewables Wind	27	Vattenfall Wind Power
14	GTC	28	Western Power Distribution

1.3. The following is a summary of the responses, together with our view on the issues raised in the responses. Please note that we will consider the responses to the questions concerning generation (DG) issues and issues with the generation part of the methodology more generally, as part of the forthcoming work on the pre-2005 issue and the planned consultation in late September/ early October on the way forward on EDCM DG charging.

Chapter 2 Questions – Overview

Question 2.1: What are your views on the key issues with the methodology we have highlighted? Are there any other issues or concerns with the methodology as a whole that we should consider?

1.4. The responses to this question focussed mainly on general issues or concerns with the methodology as a whole. A wide variety of issues and concerns were raised by respondents, and we have summarised the most common issues below.

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[47] Available at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=687 &refer=Networks/ElecDist/Policy/DistChrgs

Responses to the key issues with the methodology have generally been covered under the individual questions.

1.5. A number of respondents expressed support for the general principles and objectives behind the EDCM, with some arguing that they thought the EDCM had largely fulfilled these. One demand customer noted that they thought that the overall cost reflectivity of the model had improved over time.

1.6. The largest single concern was around the potential volatility of charges under the EDCM, with some particularly concerned that charges could change due to the behaviour of other customers, even if their behaviour remained the same. Many thought that this volatility affected the predictability of charges. The complexity in the way the model calculates charges and the fact that the full models were not available for customers to calculate (and verify) their charges were also cited as driving the concerns about unpredictability. Some demand customers were also concerned about the transparency of charges, particularly as under current Distribution Connection and Use of System Agreement (DCUSA) arrangements, DNOs may not be able to advise customers directly of their charges.

1.7. While some stakeholders welcomed the commonality of the model between DNOs, a number noted that the model was not entirely common as long as the two approaches to calculating the locational element of the charge remained (ie LRIC and FCP). There was also a concern expressed by some that they may not be able to see or respond to the pricing signals of the EDCM, such as those given by the locational charge.

Our view

1.8. We note the significant amount of work that DNOs, suppliers, LDNOs, generators, demand customers and others have put into developing and providing input into the EDCM. In approving the EDCM for demand, we think that on balance the methodology the DNOs submitted for import charges achieves the Relevant Objectives as set out in the licence.

1.9. We recognise that stakeholders have some continuing concerns about the methodology. In relation to the most significant concern – the potential volatility of charges – we note the DNOs have already commenced work in this area. In this decision, we have set out our strong expectation that we expect this work to be progressed as a matter of priority.

1.10. In requiring the methodology to be incorporated under the existing industry codes and arrangements we have enabled all interested stakeholders – not just DNOs as was the case in the past – to propose amendments to improve the operation of the methodology. We are also keen to see the concerns around the transparency of charges and the model itself addressed. We note the current DCUSA change proposal (DCP091)[48] that would enable DNOs to directly discuss charges with end customers. However, we recognise the ongoing concerns around confidentiality that prevent full models being published.

1.11. In relation to the commonality of the model, we note that 83 per cent of the average EDCM charge is calculated on a common basis. We consider this a substantial improvement on the seven different current methodologies but will monitor the EDCM for import charges as it operates in practice.

Question 2.2: Should we approve the methodology, do you agree with our proposal to implement it in full from 1 April 2012? If not, why is phasing-in charges or delaying implementation appropriate?

1.12. The majority of DNOs and LDNOs were in favour of implementing from 1 April 2012 and the majority of generators were for delay. Suppliers were split roughly equally between implementation and some form of delay or phasing (although the latter focussed on the impact on generators). Delay or phasing for some or all customers was also preferred by three of the four demand customers that responded.

1.13. The reasons for supporting implementation included a view that if the EDCM was found to be more cost reflective it should be introduced, rather than delayed or phased in. Phasing, or delaying some customers, was seen by some as overly complex and may be difficult to justify from a cost reflectivity point of view and would involve cross subsidies between customers. Some also felt that postponing implementation would further draw out a project that had already been delayed in the past.

1.14. As noted, of the four demand customers that responded, only one supported implementation in full from 1 April 2012 for all customers. The others supporting some form of phasing or delay, with one arguing that Ofgem had not sufficiently taken into account the impact of charges on customers. Support ranged from phasing only the small number of customers with large percentage rises; phasing or delay on the basis that they don’t believe they will have a realistic idea of final prices until next year and thus there is insufficient time to take mitigating action before implementation; to delay to 2015 until a single methodology (ie LRIC or FCP) could be agreed on.

Our view

1.15. In paragraph 1.22 of the main document, we set out our reasons why charges for demand customers should apply from 1 April 2012, namely:

[48] See http://www.dcusa.co.uk/Public/CP.aspx?id=109.

- We think there has been sufficient notice of the change in charges, as the DNOs published illustrative charges a year in advance of implementation.
- We have already delayed the EDCM by a year and a key reason was so that DNOs could justify some of the significant increases and consult further with stakeholders – we are of the view that this has been achieved.
- The EDCM offers mechanisms to reduce charges and we expect the DNOs to provide specific assistance to the most affected customers to identify how they can do so.
- Delay would mean deferring the benefits for those experiencing decreases in their charge as well as the broader advantages of the EDCM such as the reduction of costs for suppliers from having a common method and the opportunities the EDCM provides customers to manage their charge.
- Phasing would be complicated in terms of how it would be implemented and would have likely resulted in delayed implementation for all customers as we would have needed to consult on the phasing or delay option.
- Delay and phasing would reduce the cost reflectivity of use of system charges and would effectively result in cross subsidies between customers.

1.16. We also note that around three quarters of customers will experience reductions in their charge. Despite some large increases remaining, only four demand customers responded to our most recent consultation, and did not bring forward new evidence that suggested that delay or phasing were necessary.

1.17. We also explain why we are deferring our decision on approval of the EDCM for generation charging in paragraphs 1.9-1.13 of the main document (noting our comment in paragraph 1.3 of this appendix).

Chapter 3 Questions – Demand

Question 3.1: Do you agree with our assessment that the approach for the revenue target is reasonable?

1.18. Most respondents agreed or were comfortable with the proposed approach for calculating a revenue target for demand charges.

1.19. One supplier pointed out that in almost all areas the residual revenue to be recovered from CDCM increases ("an additional £41.3m will be recovered from CDCM customers"). The supplier was particularly concerned that CDCM customers would be impacted by changes to the EDCM and may be subject to increased volatility as a consequence.

1.20. Another respondent disagrees that asset value should be the driver for allocating indirect costs between CDCM and EDCM customers. The respondent points out that asset value is used as a driver for the allocation of indirect costs between CDCM and EDCM customers but not for the allocation of these costs to individual tariffs, because, as the EDCM submission argues, "DNO indirect costs are not considered to be closely linked to assets".

Our view

1.21. As we indicated in our consultation,[49] we think the method used for the calculation of the demand revenue target is reasonable. We are aware that the revenue to be recovered from CDCM customers is increasing in all but one area and that there may be residual volatility that flows to CDCM charges via the changing size of the EDCM revenue target. However, the estimated impact on CDCM charges is small and likewise the impact on CDCM charge volatility.

Question 3.2: Do you think the principle the maximum import capacity is a cost driver at the voltage of connection is reasonable for charging purposes?

1.22. All respondents agree that this simple principle is a reasonable compromise for charging purposes. One respondent suggests that there may be room to introduce more sophistication in the future.

1.23. In our consultation[50] we noted that for domestic customers significant diversity is applied already at the voltage of connection. We made this observation to draw attention and seek views on the principle used in the EDCM, where maximum import capacity without any diversity is used as the cost driver at the voltage of connection. Respondents argued that the diversity at higher voltage levels is substantially less than that for domestic customers connected to the lower voltage and therefore our example does not duly undermine the above principle.

Our view

1.24. We are comfortable with the principle set out above.

Question 3.3: Do you agree with our view that reactive power flows should be incorporated as part of the capacity that attracts indirect costs and 20 per cent of the residual?

1.25. In general respondents agreed with our view that when capacity is used as a cost driver it should be measured in kVA and not in kW, thereby incorporating both active and reactive power. One respondent questioned whether the "additional complexity of solving the inconsistency between using kVA and kW would offer value".

Our view

1.26. While we still think that it would be more consistent to incorporate reactive power flows as part of the capacity that attracts indirect costs and 20 per cent of the residual, we consider that the issue could be considered through the open

[49] Issue 1: the demand revenue target, page 32.
[50] Issue 2: principles guiding the use of capacity as a cost driver, page 36.

governance process. We think that the issue should be explored as part of a larger consideration of the cost drivers of these components.

Question 3.4: Is it appropriate to consider the specific assets the customer uses for the calculation of the customer's charge, or would it be more appropriate to consider only the voltage levels the customer uses for the calculation of its charges?

1.27. DNOs that responded supported the approach used in their EDCM submission where the specific assets the customer uses are considered for the calculation of its charge ("the site-specific approach").

1.28. Other respondents were split. Proponents of the site-specific approach simply stated that this approach is more appropriate as it calculates charges that more accurately reflect site-specific costs.

1.29. On the other hand, proponents of the voltage level approach invoked the practical argument that the method to assign individual notional asset values to customers involves a number of assumptions and relies only on the use of assets under normal running condition without consideration of use under contingencies. Further, one respondent argued that the site-specific approach may give a cost message that nullifies the cost message from FCP, and to a lesser extent from LRIC.

1.30. Another respondent pointed out that the voltage level approach should be less volatile and more consistent with the CDCM. The same respondent also argued that on a principle level site-specific charging is "not appropriate due to the fact that the system configuration is a result of investment decisions which have been made over a long period of time […] and the system would look very different if it were to be rebuilt completely and efficiently at any snapshot of time".

Our view

1.31. As we said in our consultation,[51] we think there are arguments on both sides and that adopting the site-specific approach with mechanisms to mitigate unintended consequences (eg the cap and collar) is reasonable. We think our condition to review the method for calculating NUFs could lead to a more appropriate application of the site specific approach.

Question 3.5: Do you think that the 'spare capacity' issue we identify should be addressed?

1.32. Most respondents agreed that the issue should be addressed in some way. One supplier argued that "where there is spare capacity on assets that is not used by anyone, it is appropriate to recover the associated costs across all users, through the

[51] Issue 4: allocation of direct operating costs, network rates and a proportion of the residual based on notional shared asset value, page 41.

scaling process", a DNO argued that "under normal circumstances spare capacity (after considering the capacity required for security of supply) is inherently there for the benefit of all users and the cost should be socialised" and an LDNO said that "on face value it does seem inappropriate that a customer should bear the sole burden of funding the operation of assets with spare capacity".

1.33. However, respondents generally advised that further work is needed to understand how to allocate costs associated with spare capacity. For example, a demand customer argued that "surplus capacity might be treated in different ways depending on where it is on the system; which is better may depend on local circumstances". One DNO said "it is very difficult in practice to determine what capacity is 'used' and what is 'spare'".

Our view

1.34. We generally agree with the responses that we received on this question and have decided to place a condition[52] on the DNOs to review the issue and modify the EDCM through the formal DCUSA change proposal process if necessary.

Question 3.6: Do you think notional asset values should take into account assets below the customer's voltage of connection?

1.35. Most respondents thought assets below the voltage of connection should not be taken into account for charging purposes although these responses did not go into much detail.

1.36. Two DNOs agreed that it would be appropriate to consider assets below the voltage of connection for the calculation of customers' charges insofar as they are used to supply these customers. However, there were arguments that customers rarely use assets below their voltage of connection and the benefit of considering these assets would be outweighed by the additional work required.

Our view

4.24. In principle, we think that under the site-specific approach it would be more appropriate to consider all assets used to supply a customer, whether the asset's voltage level is above, at or below the customer's voltage of connection.

4.25. We discussed the issue with the DNOs and while in principle they tend to agree with our view they provided evidence that suggests that the impact on charges of redressing the issue is not material. Moreover, they noted the practical difficulty of using a power flow analysis to determine asset usage below the primary substation network level (ie the High Voltage network). This would prevent taking into account

[52] Condition 3 on page 19.

assets below the voltage of connection for those customers at the lowest level in the EDCM (ie connected at High Voltage and metered at a primary substation).

4.26. Given the low materiality and the issue concerning assets below the primary substation network level, we have decided not to place a condition in this area but to encourage the DNOs to review the issue in their methodology working groups.[53]

Question 3.7: Are there any other demand specific issues that you think we should consider as part of our decision?

4.27. One respondent questioned whether pension costs should be part of the fixed adder. They argued that these costs relate to staff cost spread across the various voltage levels while higher voltage level customers do not use the lower voltage levels. Another respondent expressed dissatisfaction from the fact that demand customers are not given a credit in a "generation rich zone".

4.28. A DNO argued that capitalised operation and maintenance (O&M) costs paid by EHV demand customers need to be recognised. The DNO indicated that if no refund arrangements are put in place, it will seek a derogation for these customers.

Our view

4.29. We think that the argument on pension costs may need to be reviewed under open governance with supporting evidence. The issue of credits to demand customers has been discussed in the working groups and a decision was taken not to provide credits. The decision was based on arguments such as that demand is intermittent by nature and therefore does not provide network support that would allow the deferment of reinforcements and that it would not be appropriate to encourage energy consumption. Absent further evidence, we think the decision was sensible.

4.30. In respect to the argument on demand customer that paid capitalised O&M, we are committed to review any derogation based on its merit. We said in the past that DNOs should provide solid evidence to support any claim for a derogation.

Chapter 4 Questions – Generation

Question 4.1: Do you agree with our proposal to modify the generation revenue target in order to avoid double charging for operations and maintenance costs on sole use assets? This issue aside, do you agree with our view that the approach to calculating a generation revenue target is reasonable?
Question 4.2: Do you agree with our assessment that the approach to scaling is reasonable?

[53] Development issue 3, page 31.

Question 4.3: Do you think it is appropriate for only units exported by non-intermittent generators during the super-red time band to be eligible for credits?
Question 4.4: Do you agree with our proposal that intermittent DG should be eligible for credits as they are deemed to provide network benefits under ER P2/6? If they do become eligible for credits, should the credits only relate to units exported during the super-red time band or is a single credit rate to all units exported more appropriate?
Question 4.5: On import charges for generation dominated mixed import-export:

- Do you agree with our suggested alternative to using the collar of the network use factor for the calculation of the import tariff?
- Do you think that the methodology is appropriate for demand customers connected to generation dominated assets?

Question 4.6: Are there any other generation specific issues that you think we should consider as part of our decision?

1.37. These will be addressed as part of the forthcoming work on the pre-2005 issue and the planned consultation in late September/ early October on the way forward on EDCM DG charging.

Chapter 5 Questions – Licensed Distribution Network Operators (LDNO)

Question 5.1: Do you agree when calculating LDNO charges that DNO costs upstream and downstream of the point of connection should be considered?

1.38. See our summary and response to Question 5.3 below.

Question 5.2: Do you think that DNOs should provide LDNOs with a discount on all non-asset based charges?

1.39. This question concerned the issue of whether the proposed 50 per cent discount on indirect costs for LDNOs should be extended to cover other elements that relate to indirect (non-asset) costs, such as the 20 per cent of residual revenue.

1.40. Respondents to this question (primarily LDNOs and DNOs) generally thought that it was appropriate to extend this discount to the 20 per cent of residual revenue. One DNO did not state a position, but suggested DNOs reconsider the issue. Another DNO thought the current proposal was reasonable, but recognised scope to examine the issue of LDNO discounts on non-asset based costs. They thought that in doing so, the difference in indirect costs faced by DNOs and LDNOs should be taken into account.

Our view

1.41. We address this issue under Development issue 2 on page 30. We note that after further considering the issue, the DNOs noted some practical issues with applying this discount, especially in the case of negative scaling (which would result in an increased rather than discounted charge for the LDNO).

1.42. Our conclusion is that it is not appropriate at this time to place a condition to extend the 50 per cent discount to the 20 per cent of residual revenue. We think this issue is better considered under the open governance arrangements. We also note that this would provide scope for parties, if they wish, to consider how indirect costs are allocated between DNOs and LDNOs more broadly.

Question 5.3: Do you think that varying LDNO discounts only with the point of connection will better achieve a balance between reflecting upstream and downstream costs?

1.43. This question (and the related Question 5.1) was asked in relation to the number of customer categories used to calculate discounts for LDNOs that serve CDCM customers. Responses, mainly from LDNOs and DNOs, were mixed. The DNOs that responded generally thought that it was more cost reflective to vary the discounts based on both the upstream and downstream costs (although one thought that this issue should be reconsidered by the DNOs).

1.44. On the other hand, the two LDNOs that responded, along with a supplier and a demand customer, thought that discounts should only vary with the point of connection. One LDNO thought that this was more consistent with the way DNOs allocate costs to their own CDCM end customers. They also identified some practical issues with the DNOs' proposal. This included potential ongoing price instability as DNO network configurations – and thus the LDNO discounts – changed over time and the flow on impact this might have on any contractual arrangements they had made with customers.

1.45. Both one of the LDNOs and one of the DNOs observed that varying discounts based on the upstream costs could lead to LDNOs "cherry picking" the areas that offered the highest discounts.

Our view

1.46. As set out in Condition 1 on page 14, we have decided to place a condition to reduce the number of customer categories so that they do not vary based on the network levels provided by the DNO above the point of connection.

1.47. Our reasons are particularly on the grounds of competition, in that charges to LDNOs should not provide an unfair competitive advantage over DNOs. We also think that the cost reflectivity of charges is better met by varying discounts only on the point of connection. This is because it helps to ensure that charges are cost reflective *on average*, rather than attempting to introduce some limited site-specificity to what is fundamentally an average charging and discount model.

Question 5.4: Do you agree that it may be appropriate in some circumstances for the DNO to pay LDNOs use of system credits?

1.48. This question was asked in relation to the DNOs' proposal to cap discount percentages resulting from the extended Method M to 100 per cent (Issue 16 in our consultation). This question was not asked in relation to payment of use of system credits in respect of generation on the LDNO network. For the avoidance of doubt, the EDCM proposals do not preclude generators on the LDNO network from receiving a credit. Three respondents to this questions argued that a DNO should potentially pay an LDNO in respect of generation on the LDNO network. We confirm that this is indeed in accordance with the EDCM proposals.

1.49. LDNOs that responded to this question argued that the proposed cap is inconsistent with the treatment of the DNO's incentive revenue in Method M and that it could prevent the LDNO from recovering an appropriate margin.

1.50. Other respondents, mainly DNOs, argue that such a cap is appropriate. One argued that its absence could provide a perverse incentive for increased energy consumption and network losses on LDNOs' networks. Another argued that there may be circumstances where it may be appropriate to have a discount percentage greater than 100 per cent but that these circumstances should be dealt with as an exceptional event when they arise.

Our view

1.51. Our view is summarised in Development issue 4 on page 32. We are not aware of any LDNO that would qualify for a discount greater than 100 per cent at present nor do we think that this is likely to be an issue in the near future. On this basis, we decided not to make the removal of the 100 per cent cap a condition of our approval of the EDCM. We consider that this matter should be kept under review and if necessary a modification should be proposed under the open governance process.

Chapter 6 Questions – Common issues

Question 6.1: Do you think sole use assets should attract scaling 'costs' to the same extent as shared assets? Does the charging rate on sole use assets seem reasonable given the nature of these assets?

1.52. Responses on this issue were mixed. Some argued that sole use assets should not attract scaling either because they agreed with the DNOs reasoning (paragraphs 158-159 of the DNOs' EDCM submission, recited in paragraph 6.7 of our consultation) or under the argument that scaling detracts from cost reflectivity or under the argument that applying scaling to sole use assets will add volatility.

1.53. Other respondents argued that it is possible that sole use assets should attract scaling charges, but this rate should be lower than that on shared asset because sole use assets have different requirements and were typically fully paid for at the time of connection. One supplier said that "sole use assets should attract scaling costs to the same extent that they contribute to the costs". One DNO suggested that this should be reviewed under open governance.

Our view

1.54. In our consultation[54] we said that in our view sole use assets should attract some scaling charge, although at a lower rate than shared assets. However, we recognise the difficulties in determining the appropriate scaling charge rate for sole use assets. We said in our consultation that we think the DNOs' proposal aims to achieve a cost reflective charging rate on sole use assets and that we feel reasonably comfortable with this aspect of the methodology. We suggest the DNOs and other parties re-evaluate the issue under open governance.

Question 6.2: Do you agree with our view that the arrangements for demand and generation side management agreements are appropriate? Do you think such agreements should be available to all customers?

1.55. The majority of respondents argued that the proposed agreements are appropriate and that they should be made available to all customers. A couple of suppliers noted their concern that these agreements may conflict with contracts that the customer may have with the supplier. A couple of other respondents argued that there may be conflicts with transmission contracts both on the demand and generation side.

1.56. One demand customer pointed out that the nature of its manufacturing process will not enable it to enter into a DSM agreement. Another customer said that the impact of these agreements ought to be investigated. Respondents sought more clarity on the conditions of such arrangements and the consequence of breach.

1.57. Mathematical & Computer Modelling argued that the agreements do not appear to sufficiently reward the customer. They provide an example where a DSM with 2MVA of interruptible capacity avoids the need to reinforce an asset with a maximum capacity of 100MVA at a cost of £1m. Using the assumption that the LRIC charge for this asset is restricted through the cap, it follows that the LRIC charge is the (20 year) annuity of £1m/100MVA which is roughly £500/MVA. This suggests a value of £1k for the DSM agreement, while the market value of this agreement, ie the avoided cost, is the (20 year) annuity of £1m which is roughly £50k.

Our view

1.58. We agree with the responses that the agreements are an appropriate starting point and that they should be made available to all customers. We note that each

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[54] Issue 17: sole use asset charge, page 79.

customer should assess their own circumstances when considering whether to enter into such arrangements and whether they provide a net benefit.

1.59. We further discuss the issue and our views in more length under Customer measure 2 on page 24. We also note that the Energy Networks Association's Capacity Management Group is looking at the issue.

1.60. We welcome the example from Mathematical & Computer Modelling and hope that this can progress discussion on the issue. We think, however, that a more appropriate example might be to consider the deferment of the reinforcement project (and the value associated with this) rather than assuming that the reinforcement will be avoided forever.

Question 6.3: Do you agree with our assessment that an explicit reactive power charge is not appropriate?

1.61. All respondents to this question agreed with our assessment that an explicit reactive power charge is not appropriate.

Question 6.4: On the proposal for sense checking branch incremental costs in LRIC:

- Do you agree with our view that positive cost recovery (ie charges) and negative cost recovery (ie credits) should be considered separately?
- Do you consider that recovery from demand customers and recovery from generation customers should be considered separately?

1.62. Most respondents agreed with both proposals above. One respondent objected to the capping proposal in general, arguing that "the proposed LRIC capping is very severe and weakens the intended message. It would seem appropriate that users of a particular branch should pay for the branch reinforcement charges and for credits to generators which delay the need for reinforcement".

1.63. We note that while the proposed capping may be severe, evidence we received from the DNOs suggests otherwise. Moreover, under the proposed capping users of a particular branch would indeed be charged or credited in respect of bringing forward or deferring the branch reinforcement. The mechanism simply ensures that the totality of these payments or credits do not exceed the annuitised reinforcement cost of the branch.

1.64. Two respondents did not agree with our second proposal – that recovery from demand and generation be assessed separately. One respondent argued that "When considering revenue recovered in respect of an asset reinforcement it should be the cumulative recovered from demand and generation customers as both demand and generation will benefit from the increased in network capacity brought about by the reinforcement".

1.65. One DNO argued that while the proposals may have merit, they believe that they should be implemented in such a way that does not result in asymmetric charging in respect of a branch.

Our view

1.66. After considering the responses, we decided to place a condition[55] that recovery from positive charges and recovery from negative charges are assessed separately for the purposes of capping. We did not place a condition that recovery from demand and generation be assessed separately. This is because we think that – as we put in our consultation – while there may be an argument for such separation, there may also be arguments to the contrary. Unlike the separation of charges and credits, which received full backing from respondents, we note the separation of demand and generation did not receive full support.

1.67. Our condition does not seek to impose symmetric charging between charges and credits in respect of the same branch. We discuss our reasons above. We note that we discussed the issue with the DNO in question and they indicated that when the separation is only on the basis of charges and credits (and not demand and generation) their argument for symmetric charging is not as strong.

Question 6.4 [sic]: Do you think the EDCM should include a mechanism to mitigate the potential volatility from network use factors? We welcome views on measures to mitigate volatility and help customers manage volatility.

1.68. Most respondents expressed concern about the potential volatility of charges resulting from the EDCM. Further, there was general support for long term products which would ensure a more stable charge, although at our consultation workshops, some noted that this may affect the volatility of those who have not fixed their charges.

1.69. On the question on whether the EDCM should include a mechanism to mitigate the potential volatility from network use factors, there was a contrast of opinion between DNOs on the one hand and suppliers and customers on the other hand.

1.70. DNOs that responded argued against introducing such measures as they would inevitably erode cost reflectivity of charges. One DNO suggested that it would be more appropriate to help sites manage charge volatility. Another respondent argued that at present there is no evidence that NUFs introduces significant external volatility and that a study to obtain such evidence would be useful.

1.71. Suppliers and customers, on the other hand, were all supportive of introducing a measure to mitigate potential volatility from NUFs. Respondents argued that this will contribute towards more stable charges. Moreover, there was an argument that

[55] Condition 2, page 17.

the use of a rolling average for NUFs would be consistent with measures taken to smooth input volatility in the CDCM.

Our view

1.72. We think the issue of volatility in the EDCM should be dealt with as a matter of priority. We discuss the issue in more length under Customer measure 3 on page 26.

Appendix 2 – Direction to approve the EDCM for import charges and notice of conditions of our approval

Direction pursuant Standard Licence Condition 50A.20 of the Electricity Distribution Licence to approve the Extra High Voltage Distribution Charging Methodology for import charges subject to conditions

Notice pursuant Standard Licence Condition 50A.22 of the Electricity Distribution Licence to approve the Extra High Voltage Distribution Charging Methodology for import charges subject to conditions

Whereas

1. Standard Licence Condition 50A ("SLC 50A") of the electricity distribution licence (the "Licence") requires a Extra High Voltage Distribution Charging Methodology ("EDCM") to be developed and brought into force by Distribution Service Providers[56] on 1 April 2012.

2. Pursuant to SLC 50A.17 the Distribution Services Providers submitted the EDCM to the Authority for approval on 1 April 2011.

3. The Authority has carefully considered the EDCM and the responses received in relation to its consultation dated 20 May 2011.[57]

4. Pursuant to SLC 50A.20 the Authority, having regard to its principal objective and duties under the Electricity Act 1989 (the "Act"), proposes to approve the EDCM for import charges and subject to conditions, for the reasons set out it its decision document (Electricity distribution charging methodologies: decision to approve the distribution network operators proposals for the higher voltages)[58] dated 6 September 2011 on the basis that it achieves the Relevant Objectives.[59]

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[56] Distribution Service Providers are licensed electricity distributors in whose electricity distribution licence the requirements of section B of the standard licence conditions have effect.
[57] Electricity distribution charging methodologies: distribution network operators' (DNOs') proposals for the higher voltages - (Reference number: 67/11), 20 May 2011.
[58] This can be obtained from Ofgem's website at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx.
[59] The Relevant Objectives are set out in SLC 50A as:

50A.7 The first Relevant Objective is that compliance with the EDCM facilitates the discharge by the licensee of the obligations imposed on it under the Act and by this licence.

50A.8 The second Relevant Objective is that compliance with the EDCM facilitates competition

5. Pursuant to SLC50A.20(b) this Direction relating to approval of the EDCM for import charges has immediate effect.

6. Pursuant to SLC 50A.22 the Authority gives Notice that it proposes to approve the EDCM for import charges subject to certain conditions (the "Conditions") that require the Distribution Services Providers to undertake further action to ensure the EDCM for import charges would better achieve the Relevant Objectives.

7. Pursuant to SLC 50A.22(a) the Conditions are set out in Annex 1 to this direction. The Annex sets out the nature and contents of the Conditions and, pursuant to SLC 50A.21(b), the time by which such action should be completed.

8. Pursuant to SLC 50A.22(b) the Distribution Services Providers have until **5 October 2011** to make any representations or objections in respect the Conditions.

9. This Direction takes effect on the date below and shall continue to have effect unless revoked, amended or replaced by the Authority following consultation with the Distribution Services Providers.

Now therefore

In accordance with the powers contained in SLC 50A of the Licence, the Authority hereby approves the EDCM for import charges subject to the Conditions and gives Notice of those Conditions.

This constitutes notice pursuant to section 49A of the Act

…………………………………………………
Stuart Cook
For and on behalf of the Authority
6 September 2011

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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.

50A.9 The third Relevant Objective is that compliance with the EDCM 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 licensee in its Distribution Business.

50A.10 The fourth Relevant Objective is that, so far as is consistent with the first three Relevant Objectives, the EDCM, so far as is reasonably practicable, properly takes account of developments in the licensee's Distribution Business.

Annex 1

The reasons behind the Authority's decision to apply conditions are as follows:

Number of discount tariffs (connection types) applicable to LDNOs

In our consultation document we stated that "We do not think that it is consistent to vary the discount with the assets provided by the DNO because the charge to the end customer (the 'all the way charge') is the same for CDCM customers regardless of the assets provided by the DNO. We think that doing so has the potential to distort competition and does not appropriately reflect differences in the relevant costs.

We have decided to place a condition on the DNOs to reduce the number of customer categories for LDNO discounts so that discounts do not vary with the network levels the DNO provides above the point of connection. This means that in England and Wales the number of customer categories for LDNO discount would reduce from 15 to five and in Scotland it would reduce to three.

This condition must be met **by 30 November 2011**.

To modify the method of sense checking of branch incremental costs in LRIC

In our consultation document we stated that in relation to the application of caps on the amount that can be recovered from LRIC charges applicable to each branch, "we think that overall cost recovery should consider positive recovery and negative recovery separately". We think it would more accurately reflect the costs of future reinforcement to ensure that total charges paid in respect of bringing forward the expected time of reinforcement of a branch do not exceed the (annuitised) reinforcement cost of the asset. Similarly, we think that total credits paid for deferring the expected time of reinforcement of an asset should not exceed the (annuitised) reinforcement cost of the asset.

We have decided to place a condition on the DNOs to amend the sense checking mechanism such that positive cost recovery and negative recovery are separately assessed against the reinforcement cost of the branch.

This condition must be met **by 30 November 2011**.

To review the method for calculating network use factors

In our consultation document we stated that we thought there might be an argument that "where there is spare capacity on assets that are not used by anyone, it might instead be appropriate to recover the associated costs from all network users, through the scaling process". We stated that we were considering making it a condition of our approval of the EDCM that the DNOs investigate the issue and if necessary bring forward proposals for addressing the issue.

We have decided to place a condition on the DNOs to conduct further investigations into the issue, including an open consultation with relevant stakeholders, and to provide a report to us on the issue by **1 June 2012**. The report must:

- Examine the circumstances in which it may or may not be appropriate to socialise spare capacity costs and the different options which could be used to do this.
- Assess the materiality of the impact on customers charges' and whether these can be justified.
- Provide a well reasoned recommendation to change the methodology or a well reasoned report saying why no change is necessary.

This condition must be met by **1 June 2012**.

Appendix 3 – Glossary

A

Allowed revenue
The amount of money that a network company can earn on its regulated business.

Authority
The Authority is the governing body for Ofgem, consisting of non-executive and executive members.

C

Charge Restriction Condition (CRC)
These are special licence conditions that licensees must comply with as part of their licences. CRCs are modified in accordance with Section 11 of the Electricity Act. Failure to comply with CRCs can result in financial penalties and/or enforcement orders to ensure compliance.

Common Distribution Charging Methodology (CDCM)
The CDCM is the name given to the common methodology for calculating use of system charges for customers connected to HV/LV distribution systems. It was developed by the DNOs under standard licence condition 50 and was implemented on 1 April 2010.

Common Methodology Group (CMG)
The CMG was established by the DNOs in late Autumn 2008 under the auspices of the Energy Networks Association. The CMG has undertaken the development of a common methodology and governance arrangements for charging.

D

Derogation
A derogation is either a complete or partial revocation of a DNO’s licence requirement that can be granted by the Authority subject to such conditions and for such periods as the Authority may consider appropriate.

Direct operating costs
The costs of undertaking activities which involve physical contact with system assets, eg labour cost of staff whose work involves physical contact with system assets.

Distribution Charging Methodologies Forum (DCMF)
The DCMF is an industry group run by the ENA that discusses charging developments in relation to electricity distribution networks. See http://2010.energynetworks.org/distribution-charging-methodol/

Distribution Connection and Use of System Agreement (DCUSA)
The DCUSA is an industry agreement which governs connection and use of system arrangements between DNOs, LDNOs, suppliers and some generators on the distribution networks.

Distributed Generator/Distributed Generation (DG)
A generator or generation which is connected directly to a distribution network as opposed to the transmission network. The electricity generated by such schemes is typically used in the local system rather than being transported across Great Britain.

Distribution Network Operator (DNO)
One of 14 incumbent electricity distributors who have defined geographical distribution services areas and who are subject to standard licence conditions and charge restriction conditions in their Electricity Distribution Licences.

Distribution Price Control Review 5 (DPCR5)
DNOs operate under a price control regime, which is intended to ensure DNOs can, through efficient operation, earn a fair return after capital and operating costs while limiting costs passed onto customers. Each price control has typically lasted five years. DPCR5 is the existing price control that commenced on 1 April 2010 and will end on 31 March 2015.

Distribution Use of System (DUoS) Charges
Charges paid for the use of the distribution network.

E

Electricity Act 1989
Electricity Act 1989 c.29 as amended. Also referred to as 'The Act'.

Energy Networks Association (ENA)
The ENA is a trade association for UK energy transmission and distribution licence holders and operators. Its working groups are developing the charging methodologies. See http://2010.energynetworks.org

Engineering Recommendation (ER) P2/6
A guide for electricity distribution network system planning and security of supply.

Extra High Voltage (EHV)
Term used to describe the parts of distribution networks that are extra high voltage, typically these are of a voltage level of 22kV or more.

Extra High Voltage Distribution Charging Methodology (EDCM)
The EDCM is the collective name given to each of the two common methodologies for EHV UoS charging to be developed and submitted by the DNOs on or before 1 April 2011 for approval by the Authority under standard licence condition 50A.

G

Grid Supply Point (GSP)
A GSP is any point at which electricity is imported or exported between the National Electricity Transmission System and a DNO's Distribution System.

H

High voltage (HV)
Term used to describe the parts of the distribution networks typically at a voltage level of at least 1kV and less than 22kV.

I

Independent Distribution Network Operators (IDNOs)
A licensed electricity distributor which does not have a distribution services area and competes to operate electricity distribution networks anywhere within Great Britain. They are also subject to standard licence conditions and charge restriction conditions in their Electricity Distribution Licences.

Indirect Costs
The costs incurred undertaking activities which do not involve physical contact with system assets. Such costs include network policy; network design & engineering, project management; engineering mgt & clerical support; control centre; system mapping; call centre; stores vehicles & transport; IT & telecoms; property Mgt; HR & non-operational training; operational training; Finance and Regulation; CEO etc.

Intermittent generation
Generation plant where the energy source cannot be made available on demand.

K

Kilovolt (kV)
A unit of voltage (1,000 volts).

Kilovolt-ampere (kVA)
A unit of active power (1,000 volt-amperes). The values of network capacity and the loads flowing over a network are typically referred to in terms of kVA.

Kilovolt-ampere reactive (kVAr)
A unit of reactive power (1,000 volt-amperes reactive).

Kilovolt-ampere reactive hour (kVArh)
A unit of total reactive power over one hour.

Kilowatt (kW)
A unit of power (1,000 watts).

Kilowatt hours (kWh)
A unit of energy equal to the work done by a power of 1000 watts operating for one hour.

L

Licensed Distribution Network Operators (LDNOs)
A collective term that refers to both IDNOs and DNOs operating networks outside their distribution services areas.

Losses
The distribution of electricity inherently incurs a level of loss because the physical nature of distribution means that electricity is converted to other energy forms (eg heat) and in some cases electricity is illegally taken from the network.

Low voltage (LV)
Term used to describe the parts of distribution networks that are low voltage, typically consisting of a voltage level of less than 1kV.

M

Maximum Demand Condition
A condition where the network is highly loaded, which is used in network planning to identify required demand (load) driven reinforcement works.

Maximum Export Capacity
Means, in respect of a connection point, the maximum amount of electricity which is permitted by the DNO to flow into the distribution system through the connection point.

Maximum Import Capacity
Means, in respect of a connection point, the maximum amount of electricity (expressed in kW or kVA) which is permitted by the DNO to flow from the distribution system through the connection point.

Megawatt (MW)
A unit of power (1,000 kW).

Minimum Demand Condition
A condition where the network is lightly loaded, which is used in network planning to identify required generation driven reinforcement works.

Modern equivalent asset value (MEAV)
The capital cost of replacing an existing asset with a technically up-to-date new asset with the same service capability.

N

Network rates
Formerly called Business Rates. Rates payable to Local Government, as defined in CRC 2 of the electricity distribution licence.

Non-intermittent generation
Generation plant where the energy source can be made available on demand

P

Pre-2005 DG
DG whose contractual terms were agreed before 1 April 2005.

Post-2005 DG
DG whose contractual terms were agreed on or after 1 April 2005.

Primary substation
A substation at which the primary voltage is greater than HV and the secondary voltage is HV (covers 132/11kV substations).

R

Reinforcement
Network development to increase capacity in order to relieve an existing network constraint or facilitate new load growth.

S

Sole use asset
As defined in the EDCM submission.

Shared asset
Assets on the distribution network that are not "sole use assets".

Standard Licence Condition (SLC)
These are conditions that licensees must comply with as part of their licences. SLCs are modified in accordance with Section 11A of the Electricity Act. Failure to comply with SLCs can result in financial penalties and/or enforcement orders to ensure compliance.

Substation
An electrical substation is a subsidiary station of a distribution system where voltage is transformed from high to low or the reverse using transformers and/or where circuit switching takes place.

Super-red time band
A DNO specific time band, defined for the purpose of calculating EDCM charges. The time band is seasonal representing a period when the network is highly loaded and the annual simultaneous maximum demand is likely to occur.

Sustainable development
Refers to economic development which meets the needs of the present without compromising the ability of future generations to meet their own needs.

T

Transmission exit charges
Transmission exit charges are charges paid by DNOs to National Grid (in its role as GB Transmission Operator) for the use of the transmission network by the DNO.

Appendix 4 – Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

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