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Electricity distribution structure of charges project: DNOs' proposals for a common methodology at lower voltages

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Target audience: Generators, suppliers, customers, distributors and other interested parties

Overview:

Distribution network operators (DNOs) have a licence requirement to implement a common charging methodology in respect of charges at lower voltages and to introduce open governance arrangements for the methodology, by 1 April 2010.

Following consultation with their stakeholders this summer, on 25 August DNOs submitted their common use of system charging methodology for approval by the Authority. We consider the DNOs' proposal would introduce more cost reflective charges and greater transparency than arrangements currently in place, and we are minded to approve it subject to a small number of specific conditions. The DNOs' proposal would have significant impacts on distribution charges to some customer groups, specifically increasing the charges to domestic customers in some parts of the country. We have conducted an impact assessment of the DNOs' proposals and set out actions the DNOs are taking to mitigate these impacts.

We welcome views from all interested parties on our minded to decision, on our impact assessment or any aspect of detail regarding the DNO proposals.

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Context

Delivery of the electricity distribution structure of charges project is a priority for Ofgem. Given the levels of investment DNOs are forecasting on their networks between 2010 and 2015 and the challenges the networks will face as we move to a low carbon economy it is important we do all that we can to ensure charging arrangements are cost reflective. In October 2008 and March 2009 we set out our decisions concerning the charging methodology we expect to be implemented at lower voltages. In July 2009 we introduced a licence obligation on distribution network operators to implement a common use of system charging methodology and open governance arrangements at lower voltage levels on the distribution networks for 1 April 2010. From October 2009 DNOs will have an obligation to implement one of two common use of system charging methodologies at the higher voltage levels by April 2011.

This consultation explains why we are minded to approve the common method at lower voltages subject to conditions. We have worked closely with the DNOs in developing these proposals and the DNOs consulted on their proposals during the summer. There are therefore few surprises in their formal submission. This is a limited consultation which focuses particularly on the development of the DNOs' proposals since they consulted this summer.

Associated Documents

- Open letter: Update on impact of common distribution charging methodology and DPCR5 on distribution customer charges from 1 April 2010, 28 September 2009
- Open letter: Impact of common distribution charging methodology and DPCR5 on distribution customer charges from 1 April 2010, 4 August 2009
- Electricity Distribution Price Control Review Initial Proposals, 92/09, August 2009
- Delivering the electricity distribution structure of charges project: decision on extra high voltage charging and governance arrangements, 90/09, and collective licence modification proposal, 91/09, both July 2009
- Collective licence modification intended to deliver the electricity distribution structure of charges project at lower voltages, 48/09, May 2009
- Next steps in delivering the electricity distribution structure of charges project: decision document, 24/09, March 2009
- Next steps in delivering the electricity distribution structure of charges project: consultation document, 160/08, December 2008
- Delivering the electricity distribution structure of charges project: decision document, 135/08, and collective licence modification proposal 137/08, both October 2008

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Summary

This document consults on the electricity distribution network operators' (DNOs') formal proposals for distribution charging at lower voltages. The DNO proposal represents a significant milestone in the structure of charges project and we are minded to approve it subject to a number of conditions.

The structure of charges project aims to deliver more cost reflective, common and more transparent charging methodologies along with open governance arrangements. Customers are expected to benefit from the project through lower expenditure on the networks, lower supplier cost in managing a variety of methodologies and improved choice by facilitating competition from Independent Distribution Network Operators (IDNOs). More cost reflective charging is also important in the move to a low carbon economy, in ensuring that local generation and energy management are properly rewarded where they avoid the need for network reinforcement.

The proposal the DNOs have brought forward could have a significant one off impact on customer prices, assuming that suppliers reflect the changes in end user charges. Tariff changes vary widely across DNOs. On average charges are increasing to domestic unrestricted customers and to half hourly high voltage (HV) customers; charges are decreasing to non-domestic demand customers and to generation customers; and margins available to IDNOs are increasing. The magnitude of the proposed changes on specific customer groups is highly variable and in some cases significant.

In this document we set out the materiality of these changes per customer category, including how the charges would be affected if our Initial Proposals for DNO allowed revenues from April 2010 come into force. We have conducted an impact assessment and conclude that it is not appropriate to phase in the new charging arrangements even where the impact on charges is significant, as this would delay achievement of the substantial benefits associated with the new methodology the DNOs propose.

Nonetheless, we consider the DNOs have a strong duty of care to customers. We have asked DNOs to do all they can to keep their customers (including suppliers, large users, local authority and consumer groups) fully informed of potential price changes. Today we published an open letter to inform customers how DNOs propose to communicate with them and urging some DNOs to do more on this front. For example, we request they carry out teleconference seminars and one to one meetings with customers where necessary to explain the potential price changes.

We seek comments on our minded to position, our impact assessment and on steps the DNOs are taking to communicate with customers to enable them to prepare for the changes that will come into effect on 1 April 2010.

Ofgem has been urging the DNOs to introduce new, more cost reflective charging methodologies for several years. Following work that commenced in 2000, interim arrangements were put in place in 2005 with the clear expectation that DNOs would make significant progress on developing their methodologies at the earliest

opportunity and in advance of 2010, particularly concerning locational charging at the highest voltage levels and also to incorporate generation charges and to develop their charges to independent distribution networks operators (IDNOs).

Following consultation through 2008 we decided that a common methodology across all DNOs would be appropriate and we progressed licence changes in October 2008 to achieve this at all voltage levels. In June this year the DNOs agreed to licence conditions requiring them to deliver common charging arrangements at lower voltages for April 2010 with arrangements at the higher voltage levels to be developed and delivered for April 2011.

The DNOs have worked together since autumn 2008 on common charging arrangements at the lower voltage levels. They have encouraged representation from non-DNO parties on their working groups and have presented their ideas at the charging methodology industry forum as the project progressed. We have been fully involved in this process, including giving our initial thoughts on proposals as they were developed.

The DNOs consulted on their proposals in June/July 2009 and have subsequently developed their models following respondents' (and our initial) views on a number of detailed matters. The DNOs' charging models and their project working / consultation papers are available to view on the Energy Network Association's website. Whilst the models are detailed, their publication has enabled interested parties to understand the modelling behind the proposed method.

Given our earlier decisions on the methodology and the DNOs' consultations, this is a four week consultation which is limited to key areas where the methodology has developed since our decisions along with key areas where DNOs have filled in gaps in our earlier decisions. For example, we asked DNOs to work with IDNOs on the IDNO-related element of the methodology and we also asked DNOs to develop the approach to ensure the charges matched allowed revenue for each DNO. We set out our minded to decisions on these areas. We also provide an impact analysis now that final models have been submitted.

Our high-level view is that the common methodology at lower voltages should be approved subject to a number of specific conditions. These conditions are summarised in table 2 to this document, and include, for example, a review of the approach to generation charging where generators impose a cost on the network and elements of the DNOs' approach for charging IDNOs. Alongside these conditions we set out areas where we consider the methodology should be further developed and improved over time through open governance arrangements.

These proposals are a culmination of a number of years' work and represent a significant milestone in the path to common, more cost reflective and transparent charging arrangements. The common methodology can be developed over time under open governance arrangements with input from industry parties which is a significant step forward for the industry. The governance arrangements are being progressed via a change to the Distribution Connection and Use of System Agreement (DCUSA).

1. Electricity distribution structure of charges project context

Chapter Summary

In this chapter we set out the background to the DNOs' work on a common methodology at lower voltages and the context of the minded to decisions contained in this document. We also explain the structure of the remainder of this document.

Progress on the structure of charges project

Background

1.1. On 25 August 2009 distribution network operators (DNOs) submitted their common charging methodology to the Authority for approval in respect of use of system charges at lower voltages, specifically charges at high (HV) and low voltages (LV). This is in line with licence condition 50 of the electricity distribution licence which requires the DNOs to bring forward common UoS charging arrangements by 1 September 2009 for implementation from 1 April 2010.

1.2. This milestone is the culmination of a number of years' work to ensure the charging regime remains fit for purpose given developments on the distribution networks, such as increases in distributed generation on distribution networks and the levels of investment by DNOs reinforcing their networks which makes it more and more important to signal to customers where there is spare capacity on the network.

1.3. In 2005 use of system charges for generators were introduced along with a common connection boundary across demand and generation connections. This was noted at the time as an 'interim' step on the way to more substantive changes to methodologies, particularly surrounding developments at the highest voltage levels where we have consulted since 2000 on achieving more forward looking, locationally-based charging models. For some time we have also flagged the need for action by DNOs concerning the development of charging arrangements to independent DNOs (IDNOs) and the need for more cost reflective generation charging arrangements at lower voltage levels to enable parties that provide a benefit to the network by deferring network reinforcement to be rewarded for this.

1.4. Through 2007 and 2008 we flagged the slow progress by DNOs in delivering changes to their charging methodologies. In April 2008 we consulted on the costs and benefits of a common charging approach, and asked stakeholders whether we should prescribe the approach to apply. A majority of respondents supported a common method and said that we should determine the approach. We issued a further consultation in July 2008 on the charging approach to apply - incorporating charges at lower voltages based for demand customers on the distribution reinforcement model (DRM) in use by the majority of DNOs - and consulted on common open governance arrangements designed to allow users to raise modifications to the methodology as well as allowing for ongoing development.

1.5. Following these consultations, in October 2008 we set out our decision on the methodology to apply and we proposed licence conditions via a collective licence modification (CLM) proposal to achieve commonality across voltage levels along with common open governance arrangements. Incorporation of new licence conditions is subject to a vote by network operators and these proposals failed due to a blocking minority of DNOs on the issue of the common approach we determined at the highest (extra high, EHV) voltage levels.

1.6. In December 2008 we consulted on the next steps for the project and followed this consultation with our decision in March 2009 to split the project between lower and higher voltage levels to enable delivery at lower voltages in new charging arrangements from 1 April 2010, to coincide with the start of the new price control (DPCR5). Following our March 2009 decision we worked with DNOs on drafting licence conditions to require delivery of the common approach to us by 1 September 2009 with the intention of delivery in charges from 1 April 2010 and we consulted on these conditions in May/June. There were no objections to these licence conditions at lower voltages and the new licence conditions took effect from 1 July 2009.

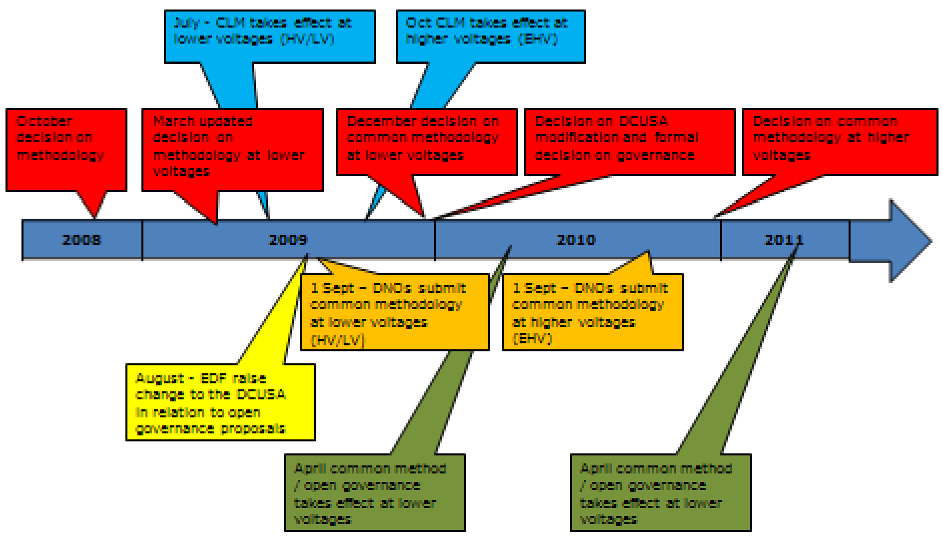
1.7. In July 2009 we issued a decision on the methodologies to apply at the EHV levels and consulted on the licence changes required to formalise the requirement on DNOs to deliver this element of the project by April 2011. These licence changes have been accepted by network operators and are effective from 1 October 2009. The statutory consultation on new licence conditions also made licence changes to allow the changes the DNOs considered necessary to allow for incorporation of open governance arrangements in to the Distribution Connection and Use of System Agreement (DCUSA) code. Our July 2009 decision set out that we would not issue a formal decision on the governance arrangements that have been developed until these arrangements have been through the necessary DCUSA modification process.

1.8. Figure 1 below shows the key project milestones from our decision in October 2008 on the methodology to apply on to delivery of the project at all voltage levels by 1 April 2011.

Stakeholder engagement

1.9. Through the project we have encouraged DNOs to engage with their customers. The DNOs have invited stakeholders to participate in work stream meetings on the project and held a workshop on their proposals in June. Following the publication of DNOs' consultations on their proposed methodologies and models at lower voltages in June and July and our publication of the initial proposals for the next price control in early August, we published an open letter flagging[1] that the combination of this project along with the new DPCR5 price control could have a significant impact on charges to some customer groups. We provided an update to this open letter in September[2] to highlight this consultation on the CDCM and to set out the DNOs' strategies for communicating the impact of this project and the price control with their customers. In this letter we urge DNOs to provide for forums such as workshops, teleconference seminars and one to one meetings with industry parties where they have not already done so.

Figure 1 - Project milestones: delivery of common methodology and governance



1.10. The impact assessment presented in this document considers this issue further. The project is expected to deliver a benefit to customers and whilst there is a step change in charges, we consider that this has been mitigated by the early visibility of these potential impacts via the publication of the DNOs' models and their submission to us[3], which sets out illustrative tariffs. Tariff changes vary widely across DNOs and the magnitude of the proposed changes on specific customer groups is highly variable and in some cases significant. On average charges are increasing to domestic unrestricted customers and to half hourly high voltage (HV) customers;

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[1] Available on our website at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=488&refer=Networks/ElecDist/Policy/DistChrgs.

[2] Available on our website at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx.

[3] The DNOs' submission to us is published as a series of associated documents to this consultation document. The DNOs' submission is also available on the Energy Network Association's website at http://2009.energynetworks.org/structure-of-charges/.

charges are decreasing to non-domestic demand customers and to generation customers (for which use of system charges are generally becoming credits); and margins available to IDNOs are increasing.

1.11. We are aware that the mechanics of the methodology may be difficult to understand from a cursory examination of the model, and we note the DNOs' role in explaining their models to customers. We also recognise our role in aiding accessibility and transparency of these arrangements. In Chapter 2 we provide an overview of the working of the methodology and set out key drivers of tariffs.

Our minded to decisions

1.12. Standard licence condition 50 requires the DNOs to bring forward a common distribution charging methodology (CDCM) which they believe is capable of approval by the Authority. Since autumn 2008 the DNOs have been working with us and other stakeholders to implement an approach broadly in line with our October 2008 and subsequent March 2009 decisions[4]. In our October 2008 and subsequent documents we have stressed that the decisions we have provided constitute the first step in providing a clear direction as to the approach to be applied, and that the methodology would necessarily need to improve and evolve both through further work by DNOs and ongoing common governance arrangements.

1.13. In these earlier decisions we specifically noted areas where the DNOs would need to do further work prior to submission to us, for example in respect of the revenue matching approach to apply and the form of final tariffs. We also noted that the approach to charging IDNOs would need to be developed by DNOs working with IDNOs and we have facilitated specific working groups on IDNO charging. Our October 2008 decision was subject to minor revisions in March 2009 following ongoing development work on the project.

1.14. Given the extent of consultation on the underlying 'baseline' methods, this document focuses on areas where the DNOs have developed the charging approach since our October 2008 and March 2009 decisions, including where they have filled in gaps in the suggested approach and where they have deviated from our original decisions. Table 1 below summarises key areas of work by the DNOs. We have provided informal feedback to DNOs through the development phase of their common methodology; the DNOs recognised and consulted on our feedback in their June consultation and July supplementary consultation with stakeholders[5].

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[4] Available on our website at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx, document ref 135/08 (October 2008 decision) and 24/09 (March 2009 decision).
[5] The DNOs' June consultation and supplementary consultation materials are available at http://2009.energynetworks.org/structure-of-charges.

Table 1 - Key areas of methodology and DNO treatment in their CDCM submission against our October 2008 / March 2009 decision documents

	Followed Ofgem decisions	Further developed	Filled gap	Deviated
DRM based HV/LV charging methodology	√			
Approach to design and costing of 500MW model		√		
Treatment of replacement costs of contributed assets	√			
Yardstick unit costs based on contribution to system maximum demand	√			
Treatment of operating expenditure		√		
Allocation of yardstick costs to unit, fixed and capacity charges			√	
Time of day charges			√	
Tariff structure		√		
Reactive unit charge				√
Revenue matching		√		
Generation charging				√
IDNO charging			√	

1.15. Since consulting with the industry on their common proposals this summer, DNOs have developed their approaches in a few areas, including the scaling of charges from their charging model to meet allowed revenues, charges to IDNOs and to considering whether the approach underlying their base models (representing a 500MW increment to the distribution system) is consistent across companies. We note that this has had an impact on the charges presented by DNOs in their submissions to us against those presented in their consultations in the summer. We carry out an impact analysis on the final populated models in Appendix 3 to this document and comment on these developments in Chapter 2. We seek views on our 'minded to' decision not to phase the charge changes that result from the CDCM.

1.16. Following the introduction of the licence requirement on DNOs to implement a common methodology at lower voltage levels from 1 April 2010, the licence specifies that the Authority is required to approve the DNOs' proposals for implementation in April 2010, veto them or to approve them subject to conditions.

Conditional approval of the CDCM

1.17. We consider that the DNOs have made good progress towards a common method and are minded to approve the DNOs' CDCM proposals against the relevant objectives set out in licence condition 50 subject to a small number of conditions. These conditions are in areas requiring further specific work, as detailed in Chapter 2. We summarise our minded to conditional approvals in table 2 below.

1.18. We are consulting on our minded to decision to approve the common method at lower voltages subject to conditions. We seek views on our 'minded to' decision on the proposed conditions and to understand whether there are other issues that respondents wish to raise.

Table 2 - Summary of minded to conditional approvals under the CDCM

Minded to conditional approval	Document paragraph(s)	Timescale for DNO work
Service models	2.95 - 2.96	31 Dec 2009
Network unavailability rebate payments	2.106	31 Dec 2009
Generator charging in generation dominated areas	2.100 - 2.102	1 Sept 2010

1.19. The common model will form a baseline from which conditional approval points can be delivered on and the common arrangements can be progressed through open governance arrangements. In Chapter 2 we flag areas for development through these governance arrangements. Our minded to decisions consider the common methodology as submitted collectively by DNOs. The licence allows a DNO to seek derogations away from the common approach, for example because the DNO cannot implement the changes in billing systems in time for implementation in April 2010. We will be considering derogation requests from individual DNOs this autumn, and set out the process for this in more detail in Chapter 3 to this document.

Structure of this document

1.20. Chapter 2 sets out our views on the DNOs' common methodology submission, providing our minded to decisions, backed by analysis, on key issues. We split the chapter between areas where DNOs have debated / implemented changes in approach from our earlier decision documents, areas where the methodology has been further developed since our decision documents and we comment on a number of other issues. Chapter 3 sets out the next steps for the structure of charges project at lower voltages towards the April 2010 implementation timescale, commenting on the need for DNOs to do all they can to communicate likely charging impacts to their customers along with a brief update on governance and charging at higher voltages.

1.21. Appendix 1 welcomes responses to this consultation and details who these should be sent to. Appendix 2 sets out how the common distribution charging methodology (CDCM) works whilst Appendix 3 provides our statutory impact assessment on the common methodology at the lower voltage levels including a synopsis of the impacts on average customer bills.

2. DNOs' common methodology submission

Chapter Summary

This chapter sets out our views on the DNOs' common methodology submission, covering key areas where DNOs have implemented our earlier decisions and areas where there has been development in the methodology as well as divergence from our suggested approach.

Question box

Question 1: Do you agree with our minded to positions given the arguments / analysis presented here and in the Impact Assessment in Appendix 3? If not, why not?
Question 2: Do you consider any additional areas should be conditionally approved?
Question 3: Do you consider any element of the methodology would warrant an overall vetoing of the DNOs' common methodology submission?
Question 4: Are there any additional areas you would like to flag as areas you consider warrant further work by DNOs in the future?

Implementation of our October 2008 / March 2009 decisions

2.1. Having reviewed the DNOs' CDCM submission we consider that the DNOs have implemented our October 2008 and March 2009 decision documents in most areas. This chapter sets out our minded to positions on key areas where there have been developments and changes from our earlier decision documents as well as errors or omissions in the submission.

2.2. As set out in Chapter 1, we have worked with the DNOs through the development of the common methodology and have discussed with them any change in approach from our October 2008 and March 2009 decision documents as well as areas where they have worked to fill gaps in our documents. Some areas have a greater impact on customer charges, including the method of scaling charges, the allocation of costs across voltage levels along with the method of splitting the end charge between standing and variable charging elements. We comment on these areas below.

Overview of the methodology

2.3. The CDCM represents a method for the determination of use of system charges for customers connected at each of the following parts of the network: low voltage (LV), HV/LV transformation and high voltage (HV). The CDCM builds on the concept of a distribution reinforcement model (DRM), where costs involved in meeting a permanent 500MW increment in capacity are allocated to customers to determine charges. A capacity increment of 500MW was chosen as it allows all network levels to be modelled as a fully functioning network without being too large as to dilute the marginal cost message.

2.4. The costs involved in meeting the capacity increment - the 'incremental costs' - include mainly reinforcement asset costs and the cost of operating and maintaining these assets. Reinforcement assets are modelled at their modern equivalent asset value and a nominal asset life of 40 years is used to annuitise their cost. In order to produce economically efficient charges (i.e. charges that reflect incremental costs), the allocation of costs to each customer category needs to be 'cost reflective', that is, reflecting the costs imposed by this customer type on the network. Costs are allocated across network levels and then tailored to each customer category with reference to their use of the network (coincidence) at the time of peak demand and their voltage of connection.

2.5. The revenue recovered through this model will not precisely match the regulatory allowed revenue. This is largely due to the fact that the model takes an incremental, forward looking approach, while the regulatory allowed revenue considers the full costs required to be financed by the DNO in the present, given its existing asset stock. The model scales charges to match the recovered revenue to allowed regulatory revenue. Given the model assigns a value to incremental load it is important that the revenue matching method maintains the price signals embedded in charges as much as possible. The mechanics of the model are set out in more detail in Appendix 2 in six steps accompanied by figure 6 which provides a diagrammatic description.

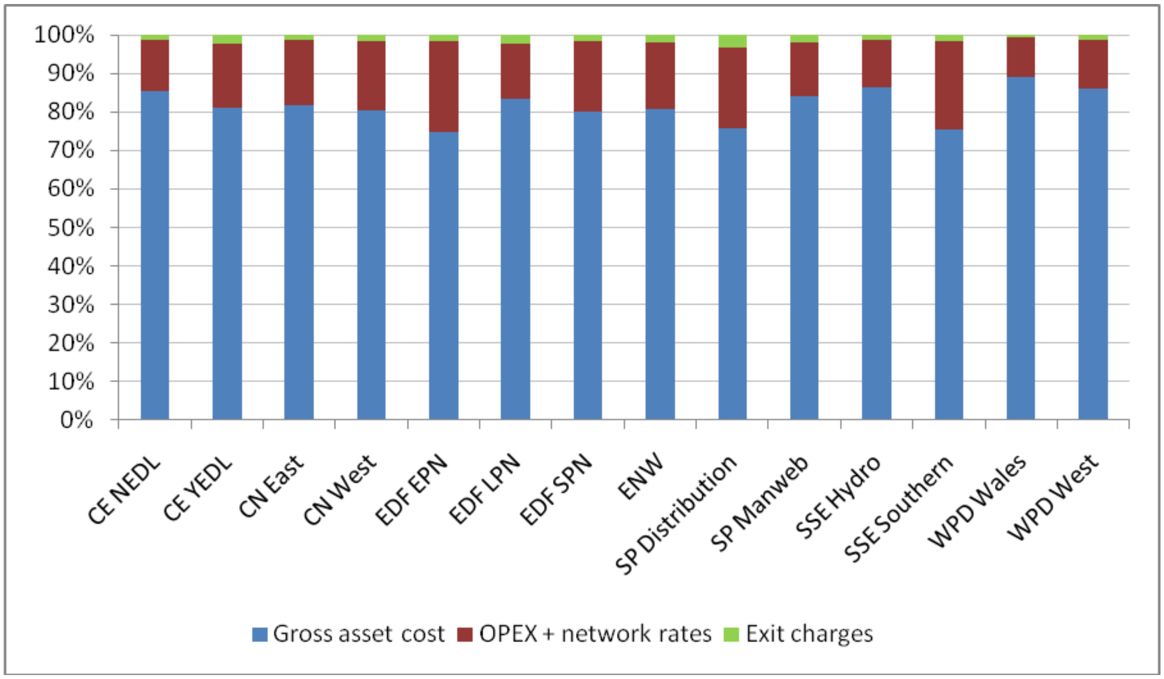
2.6. The CDCM aims to allocate use of system costs in an economically efficient (i.e. cost reflective) way amongst users in order to encourage an efficient use of the network. However, due to the complexity and number of users at the lower voltage networks it is not practical to have a specific charge for each user. Instead, for the purpose of charging, customers are placed in groups with similar characteristics, and charges are based on the characteristics of an average customer of the user's customer group.

Key areas of development following our October 2008 / March 2009 decisions

500MW network model application

2.7. At the root of the CDCM is the design of a notional network, at each network level, capable of meeting a permanent 500MW increase in capacity. The asset cost of these notional networks is the dominant cost input of the methodology. Figure 2 demonstrates the share of asset cost of total incremental cost for each licensee[6]. On average, asset costs represent about 80% of input costs into the model.

Figure 2: Share of incremental cost components in the CDCM and total value of gross incremental cost (£m)



2.8. The cost of the network model depends on the quantity and size of the assets required, and on their purchase and installation cost. Earlier versions of the CDCM showed large differences in the values of the 500MW model across DNOs. We note that differences are to be expected as these reflect variation in topography, demographics, load densities and individual procurement arrangements. The goal is to minimise to the extent possible valuation differences that stem from differing design approaches or assumptions over which costs should be included and which costs should not.

2.9. Consequently, the DNOs developed a guidance containing a set of principles and instructions that all DNOs should follow when developing the 500MW network model[7]. The guidance touches on issues such as the customer mix that should be

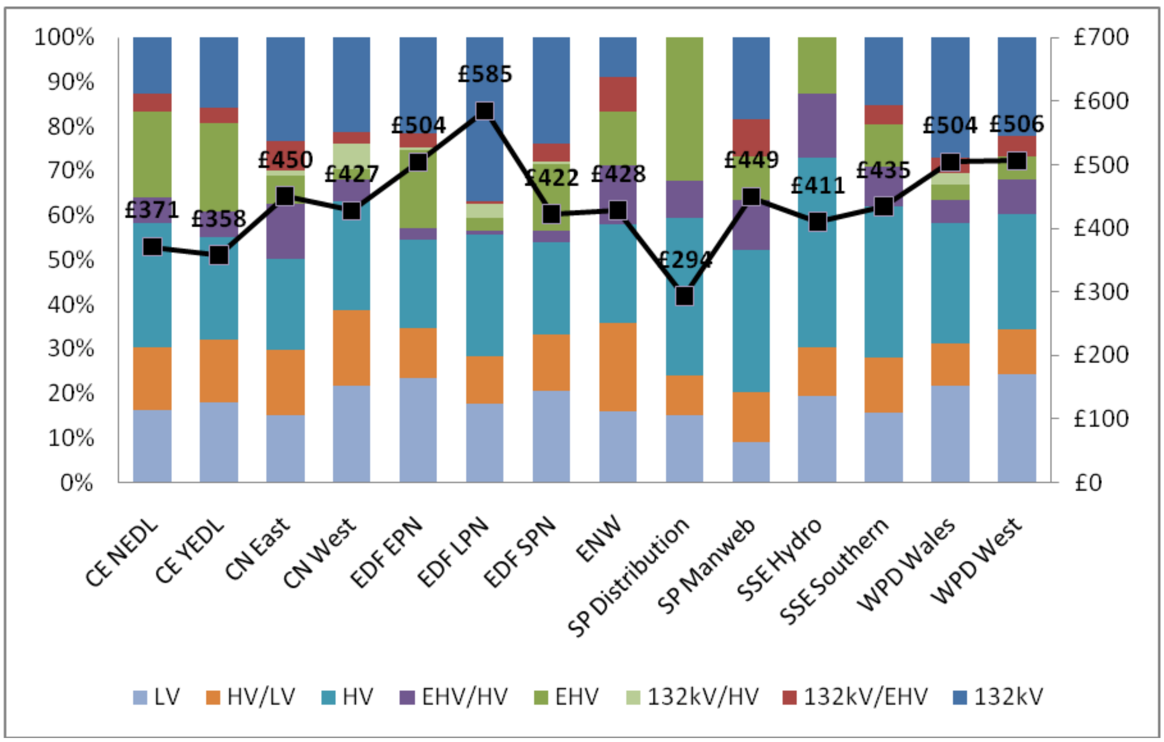
[6] Note that in Scotland the 132kV network is part of the transmission network and therefore the asset cost component does not include assets at 132kV or 132kV/EHV network levels.
[7] The guidance is included in a document entitled "Manual for the Draft Common Distribution Charging Methodology Model", August 2009 (see section entitled "Guidance on asset models"), available on the Energy Network Association's website at http://2009.energynetworks.org/structure-of-charges/.

assumed to generate the 500MW increment, the safety standards that should be met and diversity and utilisation assumptions.

2.10. We note that the values of the network models have changed significantly since the DNOs' June consultation. This has a material effect on charges and should account for part of the differences between the illustrative charges presented in the June consultation and those presented in Appendix C to their August CDCM submission. The variability in the total 500MW asset valuation across companies is still relatively wide, for example in EDF's areas the range is £422m for the SPN area, £504m for the EPN area and £585m for the LPN area. EDF maintains that this is because EPN has long lengths of 132kV network, SPN shorter lengths, while LPN has much shorter lengths but many more tunnels which are very expensive.

2.11. Figure 3 sets out the split of the 500MW model across network levels together with the total valuation of assets for each licensee. Variations in the split of assets across voltage levels are still wide. For example, the share of LV assets value in SP Manweb's area is less than half the share of these assets in several other DNOs. Similarly, the share of EHV asset value in EDF LPN and Central Network areas is in the range 2.2%-6.5% while in CE Electric areas it is circa 20%.

Figure 3: 500MW Model - network level split and total asset value (£m)



Our minded to decision

2.12. We note that the split of assets across network levels is a key driver of customer charges. It is crucial, therefore, that it is done in a consistent and cost reflective manner across licensees. Despite the improvement that the guidance brought about, we expect that further work towards commonality on the principles guiding the network model should be taken up by the industry through open governance arrangements.

Treatment of replacement costs

2.13. Network assets are funded either upfront - through customer contributions - or through use of system charges. Under the current connection charging regime, when a customer connects to the network he pays for the new assets required to connect him to the existing network along with a proportion of network reinforcement if any is required.

2.14. Accordingly, the CDCM removes from the model's incremental asset costs a percentage estimated to be contributed by customers at time of connection. The cost of their future replacement does not enter the calculation of use of system charges. This is an approach we supported previously; in our decision documents we stated in paragraph 1.30:

> "Replacement costs should not be included within this representative network. These costs are captured as part of price control revenue and therefore the scaling element of the charge should fund replacement of assets."

2.15. There has been an extensive debate on whether allowing for replacement cost of customer contributed assets in the CDCM was appropriate. The DNOs argued that these were future incremental costs, and as such, should be allocated in the same way as all other incremental costs. Our view in this debate was that such distant and uncertain cash flows should have very little impact, if at all, on present decision making. Moreover, the uncertainty may distort the cost message obtained from more immediate cash flows. We expressed that a pragmatic way forward would be to exclude the replacement cost of customer contributed assets altogether.

2.16. The DNOs consulted on the issue at length in their June/July CDCM consultations. There was little support in consultation responses for the proposal to include these replacement costs within the CDCM. The CDCM as submitted excludes these costs.

Our minded to decision

2.17. We consider that the exclusion of these costs remains appropriate and therefore we are minded to accept the DNOs' approach.

Treatment of operating expenditure

2.18. According to the CDCM, each licensee prepares a forecast of operating expenditure for the charging year. The licensee then includes 100% of the forecast of direct operating expenditure and 60% of the forecast of indirect operating expenditure as incremental costs to the charging model.

2.19. These costs are allocated to network levels according to the respective proportion of each level's modern equivalent asset value. At each network level the amount is divided by forecast simultaneous maximum load in order to obtain a unit operating expenditure (in £/kW).

2.20. The rationale for not including 100% of indirect operating expenditure is that some operating costs are not associated with a 500MW increment (indeed, some operating costs may not be associated with capacity at all). In other words, some operating costs are fixed, even to a sizeable increment of 500MW, and as such ought not to be included as incremental costs in the CDCM.

2.21. The DNOs presented evidence from linear regressions, where indirect operating expenditure was regressed against system simultaneous maximum load from HV and LV users. The regression suggested that an average of £25.4 million of indirect operating costs was fixed. A similar regression with direct operating expenditure suggested that there was no statistically significant fixed element attributable to direct operating costs.

2.22. A straightforward way to use this outcome is to exclude £25.4 million from each licensee's forecast of operating costs. This would remove a large proportion of indirect costs from small DNOs and a small proportion from large DNOs which does not appear appropriate as we would expect the operating expenditure of a large business to be less affected by a capacity increment than the operating expenditure of a small business.

2.23. An alternative use of the regression result, and the one the DNOs have adopted, would be to arrive at a fixed percentage to exclude from the indirect cost forecast. This percentage was determined by calculating the proportion of £25.4 million to total indirect cost for each licensee, and averaging across DNOs. The uniform percentage to exclude was calculated to be 40% of indirect operating cost. Under an assumption that indirect costs constitute roughly two-thirds of total operating expenditure, this amounts to excluding 26.5% of total operating expenditure.

2.24. We note that in the DNOs' June consultation the CDCM included 100% of indirect operating cost. The consultation put forward the question whether some operating expenditure should be stripped out of the model and responses were largely supportive of this exclusion. The revised approach taken in the current submission has some impact on the charges previously presented by the DNOs in their consultations, although this impact is not material.

2.25. Network rates are included as an incremental cost input to the model and are treated similarly to direct operating expenditure. The treatment of network rates has also changed since the DNOs' June consultation, where network rates were left to be picked up through the revenue matching process. Given that the change in treatment of network rates is linked to the change in the revenue matching application, we cannot isolate the impact of this change on charges.

Our minded to decision

2.26. Although we agree that it is difficult to estimate the size of the fixed costs that should be excluded from the model, we are content with the decision to exclude some indirect operating expenditure from the CDCM. We also understand the rationale for excluding a uniform proportion of indirect costs rather than a fixed amount as it is consistent with the perception that the larger the DNO, the larger the amount of indirect operating expenditure that is fixed. We are minded to accept this area of the CDCM without condition; however the industry may wish to consider this issue for further refinement under open governance arrangements.

2.27. Currently the CDCM has a single input entry, called 'other expenditure', for direct costs, indirect costs and network rates. Each component separately can provide valuable information on the plausibility of the entries, but lumped together this information is lost. The transparency of the model can be improved if each of these components were distinguished. Whilst this is not a change to the methodology we expect DNOs to progress this issue without delay.

Generator charging

2.28. In our decision documents we stated that distributed generation (DG) should receive credits where they provide benefit to the network. Such benefit will generally be incurred in a demand dominated network, where network incremental costs are driven by demand, and DG export offsets some of the demand, thereby deferring reinforcement investment.

2.29. Under the assumption that the network is demand dominated[8] we specified that a credit should be given to DGs in respect of every network level above their level of connection in recognition of the benefit DGs provide to the network. We provided the following base formula for the calculation of pre-scaled charges for generation:

$$\text{DG network level yardstick } (\pounds/\text{kW}) = -\text{F\_Factor} * \text{DRM\_Yardstick}(\pounds\ /\ \text{kW})$$

[8] Note that in Appendix 4 to our March 2009 decision document we said the method would only apply to demand dominated areas. We comment on this matter separately later in this chapter.

2.30. The formula above applies to each network level above the level of connection of the generator. The formula implies that generators receive a credit equal to the network level yardstick scaled down by a technology specific F factor[9] in recognition that not all of it can be relied on to commence output during system peak. To work out the total credit in respect of each network level, this negative charge can be multiplied by the generator's installed capacity.

2.31. Early in the development of the CDCM, the DNOs put forward arguments against the reliance on F factors and installed capacity. Their arguments, as summarised in paragraph 140 of the CDCM report, are:

- (a) Capacity-based payments would require DNOs to collect and validate information about installed generation capacities. (They say that using export capacities was not a viable alternative as it would lead to a perverse treatment of reactive power and potential perverse incentives to book unnecessary capacity).
- (b) Capacity-based payments would be open to fraud or gaming, e.g. from generators stating or installing capacity in excess of what they actually use (and therefore in excess of what actually provides benefits to the network).
- (c) Capacity-based payments would reward rarely used generators (e.g. stand-by generators) as much as regularly operating generators, even though the latter provide more benefits to the network.
- (d) To apply capacity-based payments, it is necessary to allocate generators into categories and to allot estimated F factors to each category, opening the door to disputes and perverse boundary effects. Responses to the generation consultation highlighted the large approximations that would be involved in using generic estimated F factors.

2.32. The DNOs presented an alternative method where credit to generators was based on units distributed (kWh) rather than on installed capacity (kW). According to the alternative approach, generators charges at each network level are determined according to:

$$\text{DG charge (£)} = -\text{DRM\_Yardstick(£ / kW)} * \left[\text{F\_Factor} * \frac{\text{Annual\_units\_distributed (kWh)}}{\text{Assumed\_load\_factor} * 24 * 365}\right]$$

2.33. Intuitively, as both the F factor and load factor measure availability their ratio should be very close to unity. In order to simplify the calculation, and arguably without loss of cost reflectivity, the DNOs made the assumption that, for a given

[9] The F factor represents the probability of a generator of a certain technology commencing output. Their values, as set out in Engineering Recommendation P2/6, have been determined for network system planning and security of supply purposes.

technology, the F factor and load factor are equal. With this assumption, the equation above reduces to the following[10]:

$$\text{DG charge } (\pounds) = -\text{DRM\_Yardstick}(\pounds \,/\, \text{kW}) * \left[\frac{\text{Annual\_units\_distributed (kWh)}}{24 * 365}\right]$$

2.34. We note that this equation calculates DG credit in respect of kWh export. The final generator charge may include a small, positive, fixed component in respect of operation and maintenance of dedicated assets. See the section on service models in this document for further discussion on this issue.

2.35. We note that our October 2008 decision document sets out that generator charges be applied above the voltage of connection and that the CDCM refers to the voltage of supply.

<u>Our minded to decision</u>

2.36. We believe that the high-level method described above provides the right incentive (pre scaling) for distributed generation both to connect to the network and to commence output. In addition, we believe that the working assumption that the F factor and load factor are equal is reasonable. We note that this method is a deviation from the method we prescribed in our October 2008 decision document but we consider this method to be appropriate and are minded to accept this high-level element of the methodology without condition.

2.37. In relation to the specific issue of the voltage of connection, we are not aware that the difference between the voltage of connection and the voltage of supply has been discussed, however we note that DNOs' connection charging methodologies have been clarified in recent years to specify the voltage of connection that applies for connection charging purposes to ensure there is no misunderstanding over where the point of connection is. We are minded to accept this specific feature of the methodology without condition, however given the definition in the connection charging methodology we would expect the same definition to apply in relation to use of system arrangements. We expect this to be rectified through open governance arrangements going forward.

2.38. For the avoidance of doubt, please note that this decision does not cover all aspects of generator charging and should be read in conjunction with our more detailed comments in the sections below concerning generator charging on the areas of service models, generation dominated areas and network unavailability rebate

[10] Note that at each network level an adjustment of the yardstick is made for losses and customer contributions.

payments where we are minded to issue conditional approvals on specific issues. We also ask for further work to be done to justify the non-scaling of generation charges and on IDNO generator charging and for any changes required to be progressed via open governance arrangements.

Reactive power charges

2.39. Distribution network costs are driven by its apparent power capacity (VA), which in turn is driven by users' demand or generation of real power (W) and reactive power (VAR) according to the relationship $kW^2 + kVAr^2 = kVA^2$. Reactive power adds to the capacity required to flow through the network and therefore imposes cost on the network. Reactive power charges are levied to recover the extra costs of providing this additional capacity needed to deliver the customer's requirements.

2.40. In our October 2008 decision document we described a method for the derivation of reactive power charges, which was based on a modification proposal put forward by United Utilities (now ENW) in 2005 and consulted on subsequently[11]. According to the method we prescribed the reactive power unit charge was a function of the power factor[12] of the user: the higher the power factor the lower the reactive power unit charge.

2.41. The CDCM presents an alternative method where reactive unit charges are based on the power factor of network assets at relevant network levels. For example, a unit reactive charge for an HV user depends on the power factor of HV assets and assets at higher voltages. The method is based on the principle that the cost imposed on the network by a unit reactive power depends on the power factor of the assets through which the unit flows; the poorer the power factor of the assets through which it flows, the higher the unit rate. The charge is designed to reflect the marginal cost of a unit of reactive power.

2.42. The proposed method is more demanding in terms of data requirements. It requires estimates of the average ratio of reactive power flows to network capacity at each network level. The availability and reliability of such data, in particular at lower network levels, is limited. The proposal specifies that where data is not available for a network level, data at the nearest network level at which it is available should be used as a proxy.

[11] See our website at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=3&refer=Networks/ElecDist/Policy/DistChrgMods, Reference number: 260/05.

[12] The power factor is the ratio of real power to apparent power (W/VAR).

2.43. The DNOs consulted on their alternative method in March and generally received wide support for their proposal. However, respondents raised some concerns with regard to the ability to derive reliable power factor data.

Our minded to decision

2.44. We recognise the economic basis for using the power factor and flow data of network assets for which costs are being derived and accept that the alternative method accurately measures the incremental cost of a reactive unit, and therefore appears cost reflective. We note that this method is a deviation from the method we prescribed in our October 2008 decision document but we view the DNOs' alternative approach to reactive power charging as appropriate.

2.45. We consider that the power factor will generally be known for each network level. The use of proxy data appears adequate, however this could be further refined by DNOs to ensure the use of actual data at each network level. We are therefore minded to accept this area of the methodology without condition but would expect DNOs to develop further the method around proxy data through open governance arrangements.

Allocation of costs between unit, fixed and capacity charges

2.46. In our October 2008 and March 2009 decision documents (Appendix 2, Para 1.43) we stated that the precise method by which costs are allocated between unit, fixed and capacity components will be made clear through the development of the common methodology.

2.47. The DNOs propose to use 'standing charge factors' to determine the extent to which voltage level costs are recoverable through capacity or fixed charges. This represents a deviation from our decision documents: our October decision document stated that the annuitised network cost should be allocated in proportion to each customer group’s contribution to system maximum load (i.e. by reference to a coincidence factor).

2.48. The DNOs argue that allocation in proportion to contribution to system maximum load is only practical for unit charges (p/kWh), and not for availability charges where a £/kW of simultaneous maximum load is applied to a customer’s agreed capacity. They have argued that a £/kW of simultaneous maximum load applied to a customer’s agreed capacity would result in manifest overcharging. They say that multiplying the £/kW by a coincidence factor is unlikely to be enough to solve this problem given there may be instances where a customer group has a peaky load. For this reason they propose to use standing charge factors instead of coincidence factors to allocate capacity and fixed costs to customer groups.

2.49. The CDCM prescribes the following standing charge factors (CDCM report, paragraphs 146-148)[13]:

- A fixed charge for non half hourly (NHH) settled users is based on 100% of the costs at the voltage of supply[14]. Higher voltage level costs go into the unit charge component.
- A capacity charge for half hourly substation customers is based on 100% of cost at the transformation level of supply and 100% of cost at the next voltage level.
- A capacity charge for other half hourly settled users is based on 100% of cost at the voltage of supply, 100% of cost at the next transformation level and 20% of cost at the next voltage level above.

2.50. The rationale behind the standing charge factors, as provided by the DNOs, is as follows:

- Fixed charge: the rationale has not been put forward clearly. The report mentions that the attribution of 100% of cost at the voltage of supply to the fixed component represents an element related to circuits at the voltage level of supply.
- Capacity charges: aggregate capacity requirement drives the cost of assets at the local network (i.e. the voltage of connection) and the network above. Namely, assets are sized on the basis of the aggregate capacity required by users of these specific assets, rather than on the basis of contribution to system peak load. For non-substation customers, aggregate capacity also drives the cost of feeders that go from two levels above connection into the substation above connection. These feeders represent about 20% of the cost of that voltage level.

2.51. The result of the application of standing charge factors is demonstrated in figure 4 below. The figure shows the proportion of each customer group's total revenue recovered through unit, fixed or capacity charges. These illustrative proportions represent are an average across all DNO areas. Our main observations are that:

- The fixed charge component of domestic LV customers is about 13%. The rest is recovered via the unit charge.
- The fixed charge component of non domestic NHH LV customers is about 6.5% and the rest is recovered via unit charge.
- The capacity charge component of half hourly customers is between 25-40% and the rest is recovered almost exclusively via unit charges.

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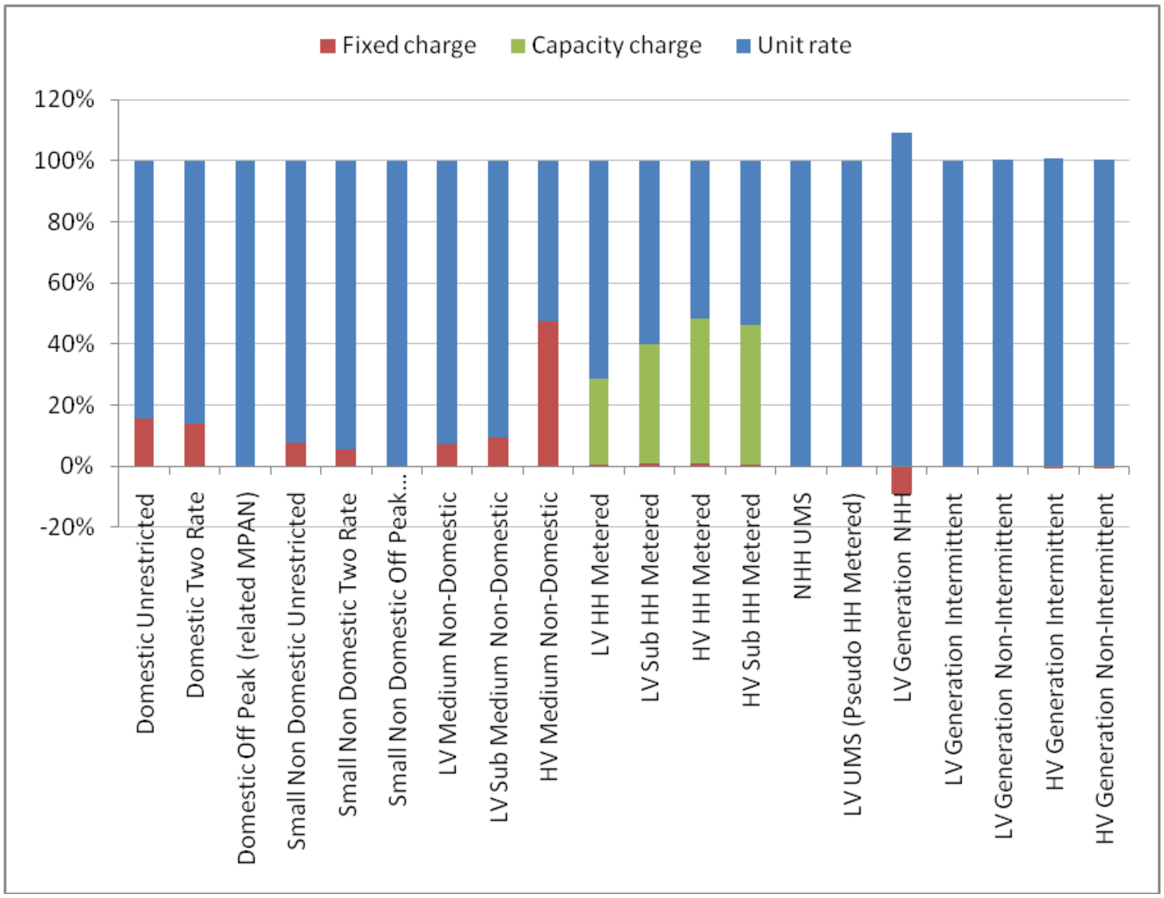
[13] In addition to this, the CDCM prescribes that fixed charges for all users (except unmetered supplies) include an element attributable to the maintenance and operation of service model assets (i.e. of sole use, non-shareable assets).
[14] Note our earlier comments concerning voltage of connection vs. voltage of supply.

- Generation credit is based almost entirely on their export capacity, with a small fixed component due to the operation and maintenance of dedicated assets.
- The cost of servicing unmetered supply (UMS) and 'related MPAN' customers is recovered only via unit charges.

Figure 4: Illustrative proportion of revenue recovered from unit charge, fixed charge and capacity charge per customer group



Our minded to decision

2.52. We recognise that the use of standing charge factors can be justified on the basis of cost drivers. While we view the approach for allocating capacity and fixed costs based on standing charge factors as broadly sensible, we are not sure whether the choice of parameters is well founded as we are not convinced that the brief justification of the effects of the methodology by DNOs is adequate or compelling.

2.53. Standing charge parameters have a strong impact on charges as they determine the balance between unit and fixed/capacity charges. Whilst some of the parameters are the same as DNOs employ currently, others are not. Given their materiality we are therefore minded to accept the method but expect DNOs to consider this matter further under open governance arrangements.

Revenue matching

2.54. A revenue matching process is required since the allowed revenue set by the regulatory price control and the recovered revenue obtained from any charging methodology will not precisely match. Table 3 presents over and under recovery through CDCM charges of each DNO relative to its allowed revenue. Currently, seven licensees over recover the allowed revenue and seven licensees under recover the allowed revenue. The over/under recovery amount will have to be eliminated through a revenue matching process.

2.55. The method for scaling of charges for the purpose of matching the recovered revenue from the model with the permitted price control revenue should endeavour to minimise any distortion to the economic signals provided by pre-scaled charges.

2.56. Our view has been that the important cost message embedded in pre-scaled charges is the differential between these charges across customer groups. We expressed our view that a matching mechanism should endeavour to preserve these differentials in absolute terms. In our October 2008 decision document we envisaged a fixed adder to be applied either to MPAN, kWh or kW in order to achieve this, but said that the details of the application need to be developed by the DNOs.

2.57. In the June consultation the DNOs used an annuity scaler (i.e. asset scaler[15]) approach for revenue matching. At the time we commented that there was no economic rationale to this approach and noted that it does not preserve cost differentials. Responses to the consultation widely supported a fixed adder application over the annuity scaler application for revenue matching.

2.58. Whilst the DNOs' initial consultation in June considered an annuity scaler rather than a fixed adder, the DNOs issued a supplementary consultation containing a fixed adder approach in early July which modelled a fixed adder to unit rates where the amount collected was proportional to the contribution of each rate/tariff to system maximum load using a single £/kW charging rate across all tariffs. This consultation paper presented charging models that incorporated this fixed adder (along with incremental operating expenditure and the exclusion of replacement costs). The use of system charges were significantly different from those presented in July.

[15] This scaler changed the rate of return on assets within the model to match to allowed revenue.

Table 3: Over/under recovery in the CDCM

DNO	Recovery	Amount (£m)	Percentage
EDF LPN	Over recovery	+113.3	+37.1%
EDF EPN	Over recovery	+103.4	+26.7%
EDF SPN	Over recovery	+33.0	+15.1%
CN West	Over recovery	+ 9.2	+3.1%
CN East	Over recovery	+ 5.6	+1.7%
SP Manweb	Over recovery	+ 1.0	+0.5%
SSE Southern	Over recovery	+ 0.6	+0.1%
ENW	Under recovery	- 1.7	-0.6%
CE YEDL	Under recovery	-31.8	-11.9%
CE NEDL	Under recovery	-39.4	-19.8%
SSE Hydro	Under recovery	-41.7	-24.2%
WPD Wales	Under recovery	-55.8	-30.6%
WPD West	Under recovery	-75.8	-30.8%
SP Distribution	Under recovery	-120.4	-33.7%

2.59. The CDCM proposal presents a revenue matching method whereby a single £/kW/year is added to demand costs at the transmission exit level. This adder flows into unit rates of demand customers and is allocated according to their contribution to demand at time of system peak. The final adder to the unit rate will not be equal across customers and the pre-scaling unit rate differential will therefore not be preserved in final charges. What will be preserved by the CDCM revenue matching application is the pre-scaling differential between total kW charges (before losses adjustment) as demonstrated in figure 5.

2.60. We note that the revenue matching mechanism in the CDCM does not apply to generators. This means that charges/credits to generators remain at their pre-scaling level. Although it is difficult to identify precisely what the discrepancy represents, a shortfall to some extent covers non-incremental overhead costs. We see no obvious reason why DGs should be excluded from such cost.

<u>Our minded to decision</u>

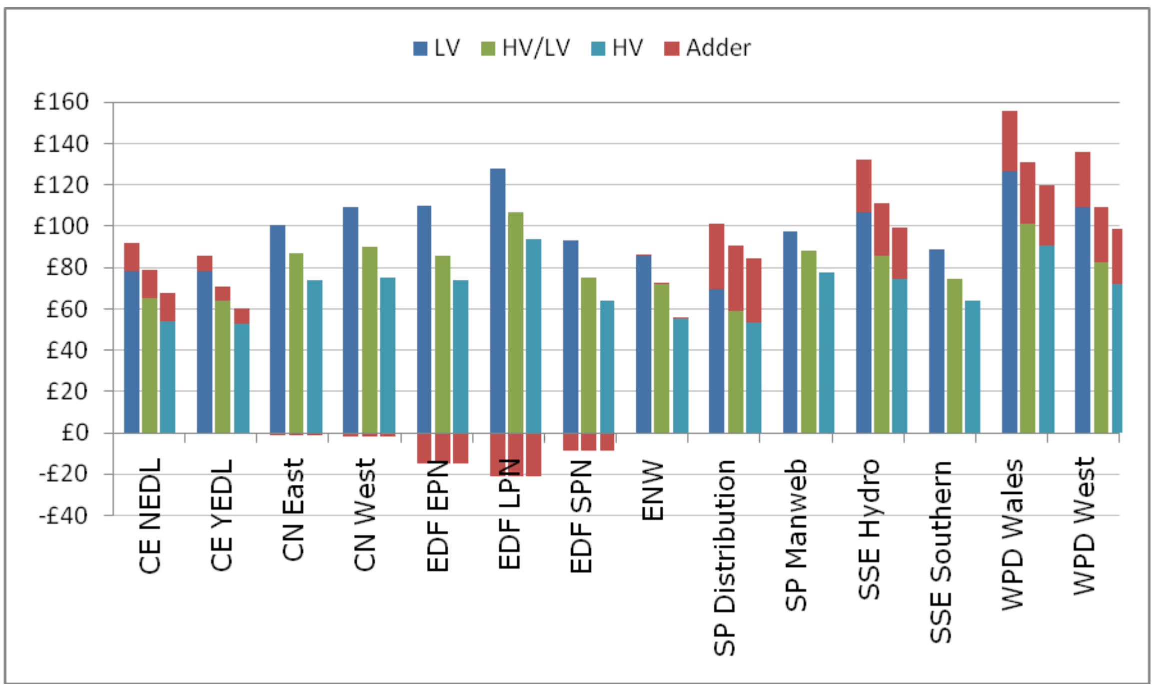
2.61. The revenue matching application put forward in the CDCM has a number of desirable characteristics: from a practical point of view it is simple and bears little risk of generating negative charges; and from a theoretical point of view it preserves the pre scaling differential in the total charge per kW of capacity.

2.62. Charges per kW of capacity are transformed into charges per kWh in order to correspond to meter reading data, which in itself presents a distortion. However, given that meters are not read continuously for the vast majority of customers, this approach should provide a good proxy for maintaining differentials between different customer groups based on contribution to peak demand, assuming profiling data is accurate.

2.63. This £/kW approach to fixed adder scaling appears appropriate given that peak demand is assumed, on average, to drive investment. In light of this we consider the approach acceptable in respect of demand customers. We expect DNOs to monitor this issue for developments on their network, for example the introduction of smart metering.

2.64. In respect of generation charges, the proposal does not provide any justification for the decision to exclude them from scaling. Moreover, the implication of this decision on demand and generation charges has not been demonstrated. We view the absence of justification and impact analysis as a weakness of the proposal. We would expect this matter to be addressed through open governance arrangements.

Figure 5: Illustrative total £/kW charge by voltage of connection (approximate) and effect of the adder application



IDNO charging

2.65. Our October 2008 and March 2009 decision documents left the matter of charges for IDNOs under the CDCM open. The methodology that has been proposed is based on a methodology that has been discussed in the joint DNO/IDNO working group and has been consulted on by Ofgem as part of joint consultation with other aspects of IDNO charging discussed at the working group[16]. We have also not vetoed interim IDNO charging modifications for WPD, SSE and SP which employ a very similar method to the one incorporated in the CDCM.

2.66. The CDCM methodology for IDNO charges is based on a separate cost allocation methodology to that used for determining end user charges. This separate method is based on a top-down allocation of allowed revenue (including all fixed and indirect costs) across network tiers. The method contrasts with the main CDCM cost allocation methodology, which first produces an estimate of incremental network costs, before allocating these costs to network tiers and customers and then scaling the resulting tariffs to ensure the full recovery of allowed revenue.

2.67. The method used to develop IDNO charges allocates cost across the network tiers (for the purposes of this model the network tiers are: EHV, HV, HV/LV and LV) to establish an estimate of the percentage of total costs that can be attributed to each tier. IDNO charges are then based on a discount from the charges that they levy on suppliers and end users[17]. The specific discount depends on the network level of connection of the IDNO network extension to which the end user is connected. Therefore, the DNO charge to an IDNO for each IDNO end user is the upstream DNO charge for an equivalent end user, less the IDNO discount relating the IDNO voltage level of connection (for that end user).

2.68. The IDNO charges are facilitated by each DNO billing IDNOs on a 'portfolio' basis. An IDNO is billed by a DNO for the portfolio of all end user connections to network extensions that it has adopted in the DNO’s distribution services area (DSA). The total charge by a DNO to an IDNO is the sum of the DNO end user charges for users connected to the IDNO network, less the IDNO discount that is appropriate to each individual end user.

2.69. In contrast with the current charging arrangements for IDNOs, the CDCM methodology provides for tariffs which are specific to IDNOs. At the time of writing, with the exception of the three not vetoed interim IDNO charging proposals mentioned above, the current charging arrangements see IDNOs charged at the boundary (of the IDNO site connection with the upstream DNO network) on the basis of a standard commercial tariff appropriate to the voltage level of connection and capacity requirement of the IDNO sites. DNOs currently bill IDNOs separately for each IDNO site that is connected to their network.

[16] See our website at: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/WPD%20CE%20and%20Reckon%20consultation_final.pdf

[17] IDNOs are able under relative price control arrangements set out in their distribution licence to levy charges for end users no greater than that levied for an equivalent end user by the upstream DNO.

Our minded to decision

2.70. Regarding the high level approach to IDNO charging, the two separate allocation methods are consistent with the view held by Ofgem that end user charges should, as far as is possible, provide end users with incremental cost signals, whilst for IDNO charging the charges should be based on a reasonable allocation of total costs to the elements of the DNOs business that are being undertaken by the IDNO.

2.71. Below we outline, in three sections, some issues with the method that Ofgem has raised in its decision letters on the interim modifications[18] and/or have been raised in discussions of the CDCM methodology at the working group. Our minded to decisions on these more detailed aspects are provided at the end of each of the three sections. Our decisions reflect our view that further work is required on the IDNO charging method through open governance arrangements going forward.

2.72. To provide some context for these discussions, we show in table 4 below the impact on IDNO margins of the proposed CDCM tariffs for domestic unrestricted customers on the LV tier. As the table shows, for most DNOs the new margins are higher than currently, particularly for small sites, but margins fall in some DNO areas for larger sites. Our understanding is that the overwhelming majority of new domestic developments are sites with less than 50 plots.

2.73. Similar tables for domestic unrestricted customers connected to the HV tier and for domestic Economy 7 (E7) customers connected to the LV and HV tiers are presented in our impact assessment in Appendix 3 below. Tables 10 to 12 in Appendix 3 show the margins for IDNO tariffs in each DNO under the CDCM. All of the tables show a similar overall trend, in that margins tend to increase for smaller sites, while for some DNOs they fall for larger sites. Table 2 is replicated in Appendix 3 for completeness.

CDCM IDNO charging

2.74. The CDCM IDNO methodology is based on an allocation of allowed revenue across network tiers. This allocation forms the basis of the IDNO discount that is applied to end user charges, or put differently, the calculation of the cost to the DNO of providing the service to the boundary with the IDNO. For an IDNO that connects to the DNO LV and HV networks the CDCM methodology provides that the direct cost percentage allocation of cost to network tiers will be adjusted by the 'LV split' or the 'HV split'(as appropriate – see paragraphs 202 and 205 of the CDCM report). The adjustment to the network tier allocations is intended to reflect the average utilisation of the network tier by IDNO's. Paragraph 192 of the report clearly sets out

[18] These decision letters can be found on our website via the link: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Pages/DistChrgMods.aspx

how each DNO should calculate its LV split, with the calculation being the ratio of average distance of DNO network required for IDNO end users to the average ratio of DNO network per DNO end user. However, the calculation of the HV split (paragraph 199) is left open, but it is noted that it should be based on the "proportion of HV network provided by the DNO in the case of HV loads supplied though a HV-connected LDNO".

Table 4: Illustrative comparison of current and proposed CDCM IDNO margins for domestic unrestricted customers connected to the LV tier

CDCM IDNO Discount		CDCM all the way (ATW)[19] bill	Proposed margin	Current Margin		
Dom UR	LV	Dom UR	All plots	25 plots	50 plots	100 plots
CN East	26.9%	£64.45	£17.34	£21.76	£15.30	£25.65
CN West	28.7%	£66.31	£19.03	£23.80	£18.00	£33.31
CE NEDL	37.4%	£66.77	£24.97	£21.55	£28.58	£27.33
CE YEDL	35.2%	£59.50	£20.94	£15.63	£24.42	£30.54
EDF EPN	18.8%	£62.95	£11.83	£9.75	£22.81	£5.20
EDF LPN	18.7%	£62.40	£11.67	(£7.61)	(£2.76)	£14.76
EDF SPN	20.9%	£64.73	£13.53	(£5.62)	£9.09	(£0.42)
ENW	30.2%	£73.30	£22.14	£11.34	£17.59	£20.28
SP Distribution	30.4%	£95.09	£28.91	£21.33	£27.73	£30.93
SP Manweb	31.9%	£85.89	£27.40	£21.33	£27.38	£29.61
SSE Southern	31.6%	£81.34	£25.70	£23.67	£27.50	£29.42
SSE Hydro	24.8%	£118.85	£29.47	£33.96	£34.79	£35.21
WPD West	34.1%	£94.75	£32.31	£21.18	£21.18	£21.18
WPD Wales	28.8%	£95.88	£27.61	£27.98	£27.98	£27.98

2.75. All DNO groups except one have calculated the HV split as being 100%, so there is no adjustment to the direct element of HV cost to reflect network utilisation. This DNO has used evidence from private HV connected networks to calculate the HV

[19] End user charges. This table (along with all IDNO-related tables in Appendix 3) calculates the all the way (ATW) charge and the proposed 'margin' based on the DNOs' illustrative CDCM charges. The margins under the CDCM proposal in the tables we publish in this document have been calculated by applying the LV or HV discount from the IDNO methodology for domestic unrestricted (UR) and domestic two-rate restricted (E7) end customers and applying it to the annual charge DNOs quote for these customer classes in their end user charging methodologies. The current margins are based on analysis DNOs have provided to Ofgem which is on a 2009/10 charging basis. At the start of July 2009, all DNOs except WPD charged IDNOs as they would any other commercial customer. This meant that different tariffs would apply to the IDNO depending on the size of the site. For example some larger sites will be subject to capacity charges. Our analysis illustrates the margins available at 25, 50 and 100 plot sites according to DNOs. Data provided by IDNOs indicates that 91% of bidding opportunities are at sites with 100 plots or less. We note that in recent weeks SP and SSE have had revised IDNO charging methodologies approved. As in most cases they follow a similar form to the CDCM, we have not included these new methods in the margin analysis presented here.

split, on the basis that these are a proxy for IDNOs. For both of these DNOs the HV split is 84%.

Our minded to decision

2.76. We do not consider that the current HV splits proposed by the DNOs appropriately reflect the usage of a DNO's network by HV connected IDNOs for the reasons set out below. Through the working group we understand that the DNOs are discussing amongst themselves the appropriate way of determining the HV split and considering compiling the evidence on the utilisation of the DNO HV network by HV connected IDNOs (in terms of distance of main) across all DNOs. We support this work and will look to the DNOs to bring forward proposals as soon as possible to improve the cost reflectivity of the HV splits taking account of the issues discussed below.

2.77. We acknowledge that because of the more limited number of HV IDNO connections within each DNO's DSA there is limited evidence on which to base the HV split. Furthermore, the greater heterogeneity of HV IDNO connections and the design of HV networks compared with LV connections mean that calculating a single representative number for the HV split is not straightforward.

2.78. We support the notion that HV (and LV) IDNO charges should reflect the fact that IDNOs utilise part of a DNO's HV (or LV) network. However, in light of the difficulties of establishing an appropriate distance based HV split outlined above we consider that DNOs, through the working group, thoroughly consider whether the data is currently available to calculate a representative and robust distance based HV split. If this data is not available then DNOs may wish to consider and develop alternative methods.

2.79. Our minded to decision is that the methodology be accepted and that this issue be worked through in more detail by DNOs working closely with the IDNOs over the coming weeks and through open governance arrangements going forward.

Charges to IDNOs for generators connected to their network extensions

2.80. Under the current charging regime IDNO sites are charged (under whichever commercial tariff has been assigned to it) by DNOs for units of electricity imported across the boundary for demand customers, net of units that are exported from the IDNO network to the DNO network due to IDNO connected generation.

2.81. The proposed charging arrangements will see all generators connected to the DNO networks charged a negative unit rate produced by the CDCM (see ‘Generator charging’ section above) and positive fixed charges for some customers (which reflect the costs of the local assets including operating and maintenance costs, net of customer contributions). The charges to IDNOs for generators connected to IDNO network extensions are exactly the same as the DNO charges for generation end users. These new arrangements appear to provide IDNOs with little or no facility to make any margin in relation to IDNO connected generation.

Our minded to decision

2.82. We consider the proposed charging arrangements for generation to be more cost reflective than the current arrangements insofar as units of electricity which are exported onto a DNO network from an IDNO network are (on average) providing benefits to the upstream network. It would seem that the appropriate party that is paid for that benefit is the generator. It is our understanding that where IDNO connected generation genuinely offsets IDNO demand then the IDNO would benefit because it would generally need to import fewer units from the DNO network yet would still be able to levy transportation charges to the end user.

2.83. However, we note that the IDNOs may incur some local network costs resulting from generation that is connected to their network extensions. These costs may be broadly equivalent to the local network costs that are embedded in the DNO generator fixed charges, where these are levied. It may be inappropriate for IDNOs to pay the fixed charge element of end user generation charges to the DNO. We would like DNOs to actively consider further options with IDNOs to improve the cost reflectivity of the charges to IDNOs for generators connected to their network extensions through open governance arrangements going forward.

Consistency and appropriateness of input data across DNOs

2.84. The analysis of illustrative margins for the IDNO tariffs proposed by the DNOs shows a significant variation between DNOs (£11.67 to £32.31 for domestic unrestricted customers connected to the LV tier). Some variation is to be expected as there are differences between DNOs' network characteristics that will affect the allocation of costs to different tiers. Furthermore, the cost allocation method relies on ten years of capex information to allocate a large proportion of the costs, and it is likely that not all DNOs will be at precisely the same point in replacement cycles for their assets, leading to different capex values. Nevertheless, the degree of difference between the margins is such (particularly the relatively low margins for EDF’s DSAs) that further analysis of the causes of these differences is required.

2.85. From our initial analysis two issues are of particular concern to us. First, there are material variations in the unit cost values for DNOs. In broad terms the outcome of the method is not affected if a DNO has persistently high or low unit costs relative to other DNOs because the allocation of its costs between voltage tiers remains broadly robust. However, the outcome of the method can be significantly affected if DNOs have relatively high unit costs for some tiers and low unit costs for other tiers because costs will be over or under allocated to some tiers. Ofgem’s analysis for DPCR5 shows that a number of DNOs have unit costs that are relatively very high (compared to an industry median) for some tiers and very low for other tiers.

2.86. Second, the results for the CDCM are based on DNOs' actual capex for DPCR4 and their forecast (FBPQ) capex for DPCR5. Ofgem’s Initial Proposals for DPCR5 propose lower capex than FBPQ numbers for all DNOs, some of which is due to unit cost affects, but some adjustments reflect the volume of capex projects. Again, if these adjustments for the volume of capex projects are not uniform across tiers, there may be a concern that using the forecast capex leads to inappropriate cost allocations. Again, our initial analysis suggests that this may be an important issue for some DNOs.

Our minded to decision

2.87. Ofgem considers (consistent with the approval of some interim IDNO methodologies in recent months) that overall the methodology used to generate the IDNO tariffs in the CDCM is broadly robust. However, our analysis suggests that it is possible for potentially inappropriate tariffs to be generated because of the input data used by some DNOs, and the sensitivity of tariffs to the input data. Our observations of the outputs from the CCDM IDNO model (see table 4) indicate that for most of the DNOs there does not seem to be any clear need for concern regarding the input data used to populate the model.

2.88. However, we are concerned that the for the three EDF companies the LV discount percentages and the LV IDNO margins are significantly lower than those of all other DNOs. We consider this to be unusual given that on the face of it, with the possible exception of LPN whose DSA includes greater London, there is nothing distinctive about these DNOs and their networks other than the fact that they are under common ownership. This suggests that for these companies the low LV percentages and LV IDNO margins are a result of the inputs used to populate the CCDM IDNO cost allocation model rather than the idiosyncrasies of these networks.

2.89. As things stand the issues associated with input data are such that they are unlikely to prevent us from approving the overall CDCM methodology. However, DNOs will need to ensure they are happy with their input costs prior to the implementation of the CDCM, as far as this is possible. We would expect DNOs to be able to rigorously justifiy their input costs and expect any anomalies to be addressed in advance of implementation of the CDCM. We have approached EDF concerning this matter. They are working with us and others to see whether it is the nature of their networks or their application of the CDCM that is giving rise to these outputs.

2.90. In the longer term it may be appropriate to consider further whether greater standardisation of certain assumptions within the method across DNOs would be appropriate. We do not want to remove appropriate differences between DSAs in terms of network configuration that may affect the tariffs that are calculated. However, it is less clear that large variations to the industry average or median in, for example, input costs, are appropriate. We will discuss these issues further with DNOs and IDNOs following our decisions on the CDCM and we would expect such changes to be progressed through open governance arrangements.

Other issues

Service models

2.91. Service models include sole use, non-shareable assets related to individual users on the network. The cost of service assets is fully covered through customer contributions, and as such are not included as part of the network model. Since the replacement cost of customer contributed assets is excluded from the CDCM, their only role is towards determining a share of operating expenditure and network rates to be attributed to each user. This share represents the cost of maintenance and operation of these assets.

2.92. Like the network model, service models should reflect the licensee's network design policy and plant types while maintaining common high level principles[20].

2.93. Generation sites may also have service models. However, since generators also have a demand meter on site, and since the demand meter will have its own service model, generators' service model is supposed to capture assets that are dedicated to the generator over and above the assets that are dedicated to the demand from the same site. Essentially this is done to avoid double counting. Where generators have a service model, it is the source of their fixed charge.

2.94. We note the generator charges set out in Appendix C to the DNOs' proposals which sets out Illustrative Use of System Charges. It appears that all DNOs except SP have determined that LV connected generators do not have dedicated assets over and above the dedicated assets in the demand service model. Hence there is no service model and a fixed charge for LV generators. For HV generators, all DNOs except for EDF have included a service model that accounts for additional protection equipment over and above the equipment required for demand customers. Therefore these generators have a small fixed charge. In conversation with SP and EDF we now believe that their different treatment is not necessarily well founded and that it will be corrected.

<u>Our minded to decision</u>

2.95. We are minded to conditionally approve the use of service models. We are concerned that the reasons for the apparent DNO-specific approaches concerning generator service models have not been set out in the CDCM report submitted to us, and we are therefore unsure whether the DNOs have taken a common approach to the use of service models. Having raised the point with the DNOs we consider that

[20] The guidance on service models is included in the same document cited in footnote 7 above.

this appears to have been an error in SP and EDF's application of the CDCM which should be rectified as soon as possible.

2.96. We are minded to approve this element of the methodology subject to the condition that the DNOs demonstrate as soon as possible, and by 31 December 2009 at the latest, that the approach submitted in the CDCM methodology is common across DNOs, and if it is not they will need to present proposals to us by that date to make it common. The impact on charges should SP and EDF change their approach to fall in line with other DNOs would be minimal but they will need to inform customers at the earliest opportunity what the revised charges are if they make these changes.

Generator charging in generation dominated areas

2.97. The CDCM states that charges for generators assume that the network is demand dominated. Our March 2009 decision document made it clear that generation charges would be negative (i.e. credits) only where the network is demand dominated.

2.98. Where generation capacity exceeds demand this could trigger the requirement to reinforce the network and will be imposing a cost rather than a benefit to the network. This could happen at any time of year, including at system peak (where demand is highest), but is likely to be most prevalent where demand is low (summer minimum demand).

2.99. We asked DNOs to provide data to us on generation and demand capacity at their substations to allow us to assess where generation could potentially be a driver of cost on the system. The CDCM considers the network as a whole and credit to generators is assigned in respect of each network level above the level of supply, including EHV network levels. Therefore we have looked at substations at the highest voltage levels (EHV) as well as at HV and LV, on the basis that a generator located at HV and LV is unlikely to confer a system benefit worthy of a use of system credit where the EHV network is generator dominated. Given the data provided we have not been able to assess whether there are or there are not instances where generation will provide a driver for reinforcing the network ahead of demand-induced reinforcement.

<u>Our minded to decision</u>

2.100. Whilst we recognise that the CDCM is a non-locational model and therefore makes some averaging assumptions, we consider that it would be entirely inappropriate to pay generators and thereby incentivise them to locate where the network is or has scope to be generator dominated. This is what underlies our March 2009 decision document.

2.101. Data submitted to us in relation to SSE's Hydro distribution area suggests generator capacity is 1.42GW and summer minimum demand (assumed as 30% of maximum demand) is 1.14GW. This data suggests that for some DNOs there is likely to be a relatively high proportion of substations where the network is generator dominated at times in the year which could be driving incremental investment to reinforce the network. We are not convinced that the data allows the DNOs to assume in the CDCM that all the networks are demand dominated for the purposes of deriving generator credits.

2.102. We note that 10GW of DG is forecast to connect during 2010-15 and that this will increase the likelihood of generation driving incremental system reinforcement. Although it is not clear that this is a significant issue today, given the points made above we are minded to accept this element of the methodology with the condition that the DNOs need to review their approach and make proposals to us by 1 September 2010 in relation to generator charging where the network is or will become generator dominated.

Generator charging from 2010

2.103. From April 2005 the connection boundary was made consistent between generation and demand customers and consequently generators, like demand customers, have been charged for using the distribution network. The boundary represents the balance between upfront connection charges in respect of new assets required to connect to the network along with a contribution to the costs of wider system reinforcement and ongoing charges for use of the distribution network. At that time we stated that existing generators would not have to pay use of system charges between 2005 and 2010, but that new arrangements may come into place at the start of the next price control period. This issue has most recently been progressed through the price control review (DPCR5) process. We have said that where DNOs do not levy charges / credits to generators it is for DNOs to satisfy themselves that this is appropriate and non-discriminatory between generators.

<u>Our minded to decision</u>

2.104. The CDCM applies to all HV/LV use of system charges. The CDCM and associated report sets out the approach to apply in respect of generator use of system charging. It does not distinguish between pre- and post-2005 generation and it is therefore clear that this approach will apply to all generators from April 2010. We are minded to approve this element of the methodology without condition. However, in line with discussions in the DPCR5 process, it remains our view that it is for DNOs to ensure they have the appropriate contracts with generators to enable them to follow the CDCM approach. Where they are unable comply with the CDCM, DNOs are required to seek a derogation for our consideration.

Network unavailability rebate payments

2.105. DNOs’ current charging methodologies set out that certain generators with firm connection rights will be allowed a rebate under the Distributed Generation Network Unavailability Rebate scheme. During the current 2005-10 price control this applies only to customers paying generation use of system charges. The DNOs do not mention network unavailability rebates in their CDCM submission.

Our minded to decision

2.106. The DNOs have not justified removing unavailability rebates from their methodology in their submission. We expect the CDCM to reinsert the methodology for calculating these rebates and our minded to decision is that the methodology for calculating these should be included in the CDCM along the lines set out in a footnote below[21]. We consider that the omission from the CDCM needs to be rectified without delay to ensure the treatment of rebates is clear and that this rebate scheme

[21] Network unavailability rebate payments: minded to decision on the wording to appear in the common methodology:-

A compensation payment may be payable to customers for network outages under two schemes. The majority of customers are compensated under the Guaranteed Standards arrangements set out in Statutory Instrument 2005 No. 1019 (The Electricity (Standards of Performance) Regulations 2005), as amended or replaced from time to time.

Customers who are off supply for greater then defined periods of time are entitled to a payment. This scheme applies to all demand customers and to all generators not included in the scheme described below.

For customers with generation connected at more than 1,000 volts the following scheme will apply. This scheme is known as Distributed Generation Network Unavailability Rebate and payments will be calculated for each generator on the following basis:

Payment = A*B*(C-D)

Where:
A = the network unavailability price of £2 per MW per hour.
B= incentivised generator capacity; the highest active electrical power that can be generated (or the relevant incremental change of this amount in cases of the expansion of existing generation plant) by the generator for the year, according to the connection and/or use of system agreement(s).
C = network interruption duration; the total duration of all occurrences (in minutes) on the distribution system each of which involves a physical break in the circuit between itself and the rest of the system or due to any other open circuit condition, which prevents the generator from exporting power. It excludes:
- 50 per cent of the total duration of cases where the DNO takes pre-arranged outages of its equipment for which the statutory notification has been issued to the generator;
- the cases where the generator has specific exemption agreements with the DNO in the connection and/or use of system agreement(s); and
- the cases which are part of exempted events in the quality of service incentive or the Guaranteed Standard Statutory Instrument (such exemptions include interruptions of less than three minutes duration and industrial action).
D = the baseline network interruption duration for the relevant year which either has a default value of zero or some other value agreed between the customer and the DNO and recorded within either; the connection offer, connection agreement and/or use of system agreement(s).

Distributed Generation Network Unavailability Rebate scheme payments will be calculated by the network operator on an annual basis (1st April - 31st March) and payments made shortly after the end of each year. This payment is automatic and does not need to be claimed by the generation customer. The de minimis level of rebate is £5.

continues to operate from 1 April 2010. We are therefore minded to approve the CDCM subject to the condition that the DNOs bring forward this change to the CDCM by 31 December 2009.

Input data

2.107. In their July supplementary consultation, the DNOs note they have been working on the commonality of input data, specifically the implementation of the 500MW asset models (see above) and the determination of customer contribution percentages. The DNOs noted that changes in these could well have a relatively significant impact on charges.

2.108. In addition to their 500MW models and customer contribution percentages, respondents to the DNOs' consultations comment that there is other input data (e.g. coincidence factors) where they are concerned about the transparency of the determination of the data that feeds the CDCM, including uncertainty over how often data might be reviewed or fixed.

<u>Our minded to decision</u>

2.109. Our view is that DNOs have taken significant steps forward over the transparency of their models but that there remains more to do. Inputs should be defined in a more transparent manner, including the method for deriving them, and it should be clear how often such inputs are revised. Without this it is unclear whether the method is strictly being applied in a common manner. Whilst we are minded to approve this element of the methodology without condition, we expect this issue to be followed up using open governance arrangements. Specifically, DNOs will need to provide parties with more information about inputs and should organise to debate variances.

Excess capacity charges

2.110. This issue concerns how to charge where a customer exceeds the maximum capacity allowed in their connection agreement. The DNOs debated the issue of excess capacity charging and found it difficult to agree their common position. Responses to their consultation were also mixed on this issue. Two issues arise: how long to charge on the basis of the exceeded amount (DNOs' methodologies currently differ) and whether to calculate a charge for the excess amount above the standard charge. The CDCM states that a customer will be charged at the standard rate for a higher requirement for the month in which they exceed capacity.

<u>Our minded to decision</u>

2.111. We consider the CDCM approach appears to be fit for purpose and are minded to approve this element of the method without condition. We have considered whether a different excess charging rate might be appropriate but concluded that we are not sure how an alternative rate would be calculated given the CDCM is effectively an average incremental model at the lower voltages. The DNOs have not made clear to us what costs are, on average, incurred in respect of customers exceeding their capacity which makes it difficult to understand whether an alternative charging approach might be more cost reflective than the existing CDCM in respect of charging customers on units that exceed their maximum capacity.

2.112. We note that levying one month's excess capacity charge may not represent a significant amount of money, however where a customer is breaching the capacity set out in their connection agreement we would expect remedial action to be taken under this agreement in any case. The connection charging arrangements effectively enable targeted action against customers where the network is constrained and where specific system reinforcement due as a result of a customer breaching capacity. Some DNOs have noted concerns with the effectiveness of reverting to the connection agreement and we anticipate they will consider this matter further under open governance arrangements.

3. Next steps

Chapter Summary

This chapter sets out the next steps for the project at lower voltages along with the project more generally. We summarise the areas where we are minded to conditionally approve the common method, and we ask DNOs to make objections or representations on these areas as part of this final consultation phase of the project.

In this chapter we also comment on the DNOs' strategies for communicating impacts to their customers and interactions with the DPCR5 project.

Conditional approval of the CDCM

3.1. The licence condition covering the development of common charging arrangements at lower voltages requires the Authority to give at least 28 days' notice of conditional approvals to DNOs in order for them to have time to consider them and to make representations should they wish to. This document consults on our minded to decisions regarding conditional approvals, pending further comments from respondents. Following the close of this consultation and consideration of responses we will issue our final decision and formal conditional approval notices. Given the timescales for the project DNOs should make representations on our 'minded to' conditional approvals as part of their responses to this document.

3.2. In addition to these conditions, and as set out in Chapter 2, we consider that a number of areas of the common methodology warrant further consideration by the industry post April 2010 under open governance arrangements. We comment on areas for further development at lower voltages separately below.

DPCR5

3.3. As noted in the impact assessment, the common methodology will take effect at the same time as a new price control, DPCR5. We set out indicative impacts of the price control as part of our impact assessment in Appendix 3, which shows that in addition to the potential price movements under the introduction of the CDCM, the initial price control proposals add around 1% to annual domestic customer bills in 2010/11. These figures are indicative at this stage and should not be taken as a forecast for charges from April 2010. We will perform further work on impacts as part of the analysis in our price control final proposals document this autumn.

DNO customer communications strategy

3.4. Given the combined impact of the new DPCR5 price control and the implementation of the common methodology at lower voltages, we have asked DNOs to do all they can to keep their customers updated on the impact on their charges.

We wrote to the chief executive at each DNO asking them to set out their plans regarding communicating with their customers and we subsequently published an open letter to customers on this matter in August[22] following the publication of our initial price control proposals[23]. In September we provided a subsequent update open letter[24] on the DNOs' responses to our letter to each chief executive.

Areas for further development

3.5. In addition to a few areas where we are minded to issue conditional approvals, we have flagged other areas in Chapter 2 where we would like parties under open governance arrangements to consider whether the approach being adopted in the common methodology is optimal. DNOs set out in their submission to us that they also intend to develop their thinking regarding long term tariff products, tariff volatility, the de-linking of tariffs from suppliers' systems and regarding portfolio billing for embedded networks.

Table 5 - summery of further work required by DNOs, predominantly under open governance arrangements

Further work required by DNOs	Document paragraph
Commonality of 500MW model	2.12
Split out operating expenditure in model for greater transparency	2.27
Voltage of supply vs voltage of connection	2.37
Reactive proxy data	2.45
Standing charge factors	2.53
Justification of the non-scaling of generator charges	2.64
IDNO charging - HV splits	2.79
IDNO charging - generator charging	2.83
IDNO input data	2.89
IDNO standardisation of assumptions	2.90
Input data standardisation and provision of greater information	2.109

Derogations

3.6. The methodology concerning charges at lower voltages is revoked from April 2010, subject to Authority approval of the common approach. However, the licence

[22] Available on our website at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=488&refer=Networks/ElecDist/Policy/DistChrgs.
[23] Available on our website at http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Pages/DPCR5.aspx.
[24] Available on our website at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx.

allows DNOs to apply for a derogation against the common methodology where they are unable to meet the 1 April 2010 implementation date. We have always recognised that whilst we expect DNOs to do all that they can to implement changes for 1 April 2010, billing system changes may take time, and we will consider derogation requests on a case by case basis and will issue our decisions after we have formally concluded our position on the common methodology in December.

3.7. The DNOs set out 'areas of risk' regarding delivery of the CDCM in Appendix E to their submission to us. Whilst a number of areas are identified it is our understanding that the DNOs will manually work around any billing system constraints in the short term unless cost/resourcing implications make this unworkable. We expect any DNO-specific derogations to be open and transparent to all customers including detailing the impact on charges away from the CDCM approach, and setting out the method to be applied if this is different from the CDCM or a DNO's existing methodology. Where a non-CDCM approach is approved, the method being applied for the duration of the derogation will feature as an appendix to the common method which will not be subject to open governance arrangements.

3.8. Although we are consulting on the CDCM and derogation requests cannot be concluded until after we have made a formal decision on the proposals, we have been clear that DNOs should seek derogation requests in a timely manner, and where possible by 1 September 2009. This was to allow us and customers to understand the impact (if any) on their charges should we grant derogation requests, and also to allow us time in the process to consult on requests this autumn should this appear necessary. To date we have received one formal derogation request (see table 6 below), therefore this needs addressing as a matter of urgency.

Table 6 - Derogation request received

DNO	Issues raised
WPD	- IDNO billing[25] - Reactive power charges - Deenergised MPANs

3.9. Derogation requests should be raised with us without delay, and by 5 October 2009 at the latest. We recognise that industry parties need to understand the potential scope of derogations at the earliest opportunity to understand any impacts on charges and/or their billing systems. We will publish derogation requests on our website[26]. We will decide whether to consult on derogation requests in October and

[25] We understand from the DNO/IDNO working group meeting of 2 September 2009 that all other DNOs are content that they can implement a temporary solution for portfolio billing, prior to an enduring solution being put in place. The minutes of this meeting are available on our website at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/IDNOs/Pages/IDNOs.aspx.
[26] Available on our website at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx.

will keep the industry updated on our plans when we have assessed DNOs' formal derogation requests.

EHV level charging

3.10. The delivery of a common methodology at lower voltages for April 2010 will be followed by the delivery of one of two common methods at EHV for April 2011 under licence condition 50A which takes effect from 1 October 2009[27]. We expect DNOs to follow a broadly similar process to the process they have taken to developing the common methodology at lower voltages, and to include and inform stakeholders as the development of the methodologies progresses. Our expectation is that the boundary between higher and lower voltages will be common from April 2011, and this issue requires further consultation by the DNOs.

3.11. The EHV charging methodology will remain DNO-specific for a year before common arrangements apply. The majority of DNOs require changes to the wording of their stand alone methodologies to allow them to refer to EHV charges only (the current methodologies refer to HV/LV and EHV charging) and some require changes to the method to, for example, roll forward the existing arrangements for another year. These changes have been (or will shortly be) proposed as modifications to their DNO-specific methodology and details are available on our website[28].

3.12. We requested that DNOs submit these modification requests by 1 September to allow customers to understand the full package of changes proposed to take effect from 1 April 2010 and to allow for consultation on these should this be necessary.

Open governance arrangements

3.13. The common methodology will be subject to governance arrangements that allow materially affected parties to raise modification proposals to the methodology. Open governance arrangements are currently being progressed through a modification to the Distribution Connection and Use of System Agreement (DCUSA)[29]. As set out in our July decision document, we will issue our formal decision concerning governance arrangements on conclusion of the process to incorporate arrangements at lower voltages in to the DCUSA.

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[27] See the licensing area of our website at http://www.ofgem.gov.uk/Licensing/Work/Notices/ModNotice/Documents1/Implementation%20Notice%20CLM%20proposal%2091%2009.pdf.

[28] See the charging modifications area of our website at http://www.ofgem.gov.uk/NETWORKS/ELECDIST/POLICY/DISTCHRGMODS/Pages/DistChrgMods.aspx.

[29] Change proposal number 46 (DCP046). Full details are available to view on the DCUSA website at http://www.dcusa.co.uk/Public/CPs.aspx.

Appendices

Index

Appendix 1 - Consultation questions

1.1. We would like to hear the views of interested parties in relation to any of the issues set out in the document.

1.2. We would especially welcome responses to the specific questions set out in Chapter 2 and which are replicated below.

1.3. Responses should be received by 26 October 2009 and should be sent to:

Ynon Gablinger
Distribution Policy, Local Grids
9 Millbank, London, SW1P 3GE
0207 901 7051
distributionpolicy@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document(s) to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Any questions on this document should, in the first instance, be directed to Ynon Gablinger.

Chapter Two

Question 1: Do you agree with our minded to positions given the arguments / analysis presented here and in the Impact Assessment in Appendix 3? If not, why not?
Question 2: Do you consider any additional areas should be conditionally approved?
Question 3: Do you consider any element of the methodology would warrant an overall vetoing of the DNOs' common methodology submission?
Question 4: Are there any additional areas you would like to flag as areas you consider warrant further work by DNOs in the future?

Appendix 2 - Overview of the CDCM

1. **Estimate the costs involved in meeting a 500MW increment in capacity**
   The (incremental) costs involved in meeting an increment in capacity are
- Asset costs; and
- Operating costs, network rates and a contribution to transmission exit charges[30].
    - Asset costs are estimated through the construction of a network model. At each network level a notional network is designed to provide 500MW of simultaneous maximum load at the grid supply point. The assets of the notional models are costed in terms of their modern equivalent asset value and their cost is annuitised.
    - Operating costs, network rates and exit charges are forecasts for the charging year. Forecasts are based on historical data coupled with the licensee's estimates of future trends.

2. **Allocate costs to network levels**
- Asset costs are allocated according to the network level of the assets
- Operating costs and network rates are allocated to each network level according to its share of modern equivalent asset value (asset replacement cost).
- Exit charges are allocated to the transmission exit level.

3. **Derive the yardstick cost of load at each network level (£/kW/year)**
- Divide network level costs by simultaneous maximum load at that level. This number will be different from 500MW due to loss and diversity adjustments.

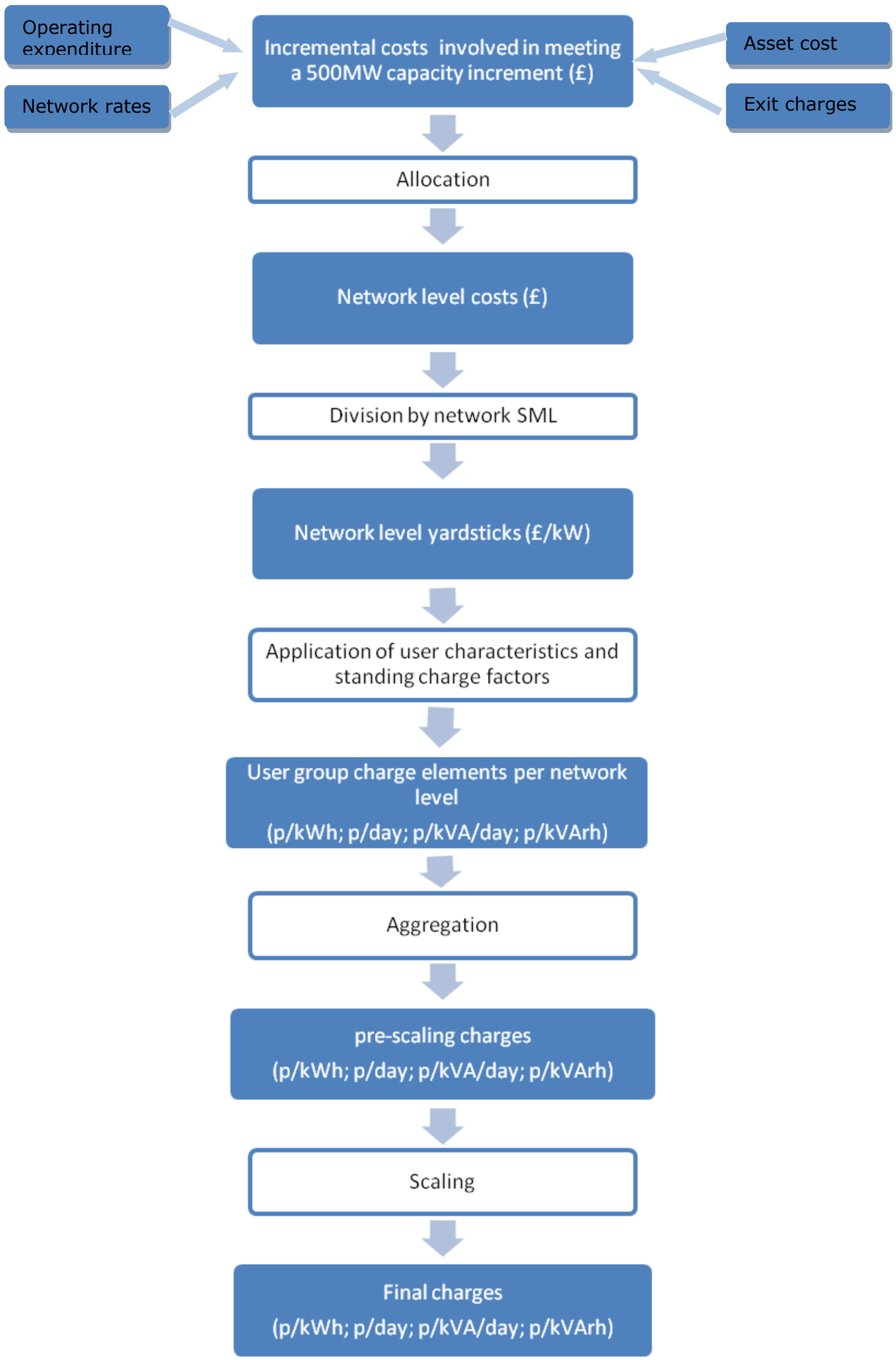
4. **For each user, derive network level unit and standing charges based on user characteristics (e.g. coincidence factors) and agreed standing factors**[31]
- Unit charges are determined on the basis of the user's contribution to simultaneous maximum load (i.e. in reference to a coincidence factor).
- Capacity charges are allocated according to agreed capacity charge factors. Capacity charges apply only to half hourly customers (except unmetered supply).
- Fixed charges are allocated according to agreed fixed charge factors.

5. **For each user, aggregate the unit and standing charge elements across the applicable network levels. The charges obtained are the pre-scaled charges.**
- Applicable network levels include the voltage/transformation level of supply and all network levels above.
- Use pre-scaled charges and consumption forecast data to determine revenue shortfall/surplus relative to the regulatory allowed revenue.

6. **Scale charges up or down to match recovered revenue with allowed revenue. The charges obtained are the final charges.**

[30] Transmission exit charges are levied on DNOs in respect of the costs of connecting the distribution network to the transmission network and represent a charge for specific connection assets at the interface between the transmission and distribution networks.
[31] Two of the tariffs (Related MPAN and unmetered supply customers) have only a unit charge component.

Figure 6: Overview of the common distribution charging model



Appendix 3 - Impact Assessment - common methodology at lower voltages

Summary

1.1. This appendix considers the costs, benefits and impact on tariffs of the DNOs' CDCM proposal for a common charging methodology at lower voltage levels.

1.2. Whilst the approach being adopted for demand customers is broadly similar to the existing approach for the majority of DNOs at a high level, changes to the models and input data have been made concerning areas such as the allocation of costs between network levels and between fixed, capacity (where applicable) and unit charges and the approach taken to matching outputs from the charging model to allowed revenue. The DNOs have also adopted a common set of tariffs, entailing a reduction in the number of tariffs for some DNOs and a consequent tariff migration for some customers.

1.3. The DNOs' submissions set out that a move to common arrangements entails some relatively significant impacts on charges for certain customer groups. Tariff changes vary widely across DNOs. On average across DNOs, charges are increasing to domestic unrestricted customers and to half hourly HV customers; charges are decreasing to non-domestic demand customers and to generation customers, for which use of system charges are becoming credits; and margins available to IDNOs are increasing. The DNOs attempt to explain significant tariff movements in Appendix D to their CDCM submission.

1.4. Notwithstanding the average changes above, some DNO areas experience steep changes in illustrative charges for some customer categories, particularly when the change to allowed revenue as per our initial proposals is factored in. These figures represent the best information available at this time and are based on some simplifying assumptions, however they are illustrative and are not a forecast of what might happen at the final proposals stage of the price control review this autumn. These figure show, for example that EDF SPN could see the charge for domestic unrestricted customers increase by 24% (corresponding to a 4-5% increase in final bills), SSE Hydro could see the charge for domestic two rate customer increase by 46% (9%), and ENW could see its NHH UMS charge increases by 146% (29%). These large changes could have large impacts on non-diversified (niche) suppliers. We ask for views on our conclusion that the charge changes that will result from the implementation of the CDCM on 1 April 2010 should not be phased in.

1.5. The commonality and transparency of the new arrangements will provide immediate cost savings to suppliers by lowering risk management and charge forecasting costs and will reduce barriers to entry for new suppliers. We understand that these savings will total multiple millions of pounds per year. This will provide longer term savings to consumers. It is also expected that the new arrangements will facilitate the development of distributed generation and help reduce carbon emission through the implementation of generation charges that reflect where generators benefit the network.

Key issues and objectives

1.6. The project seeks to deliver common charging arrangements across DNOs that meet a baseline concerning certain relevant objectives covering cost reflectivity, competition, reflecting developments in the DNOs' business as well as ensuring that the DNOs comply with the Electricity Act and their electricity distribution licence.

1.7. Following consultation in April 2008 we determined that a common methodology across DNOs was appropriate. In July 2008 we consulted on the form of the methodology that would become the common approach, incorporating an impact assessment to aid consultation.

1.8. This impact assessment is considered against the status quo. Our earlier consultations regarding the benefits of a common methodology and open governance arrangements concluded that these will deliver benefits across time concerning (i) reduced analytical and charge forecasting costs for suppliers - including a reduction in the level of the risk premia that is incorporated in to charges due to the difficulties of forecasting the impact of methodology changes and charging outcomes in the order of multiple millions of pounds per year, and (ii) benefits for all customers regarding increased transparency via the publication and commonality of the models.

1.9. One of the key objectives of DPCR5 is to ensure that DNOs facilitate the connection of low carbon technologies to the distribution network. Current charging methodologies do not provide appropriate incentive for DG take up. A new, cost reflective charging methodology should recognise where DG provide a benefit to the network and provide appropriate incentive through charges.

1.10. Generator charges in the CDCM are in general negative, in recognition of their benefit to the network. This should remove previous barriers to DG connection and play a role in reducing carbon emissions from the energy sector.

1.11. Other key benefits of the project include:

- the delivery of economically efficient charges ensuring efficient use of electricity distribution networks. This is especially important given the scale of investment being forecast on the distribution networks under DPCR5 where forecast load related investment is £2.3bn net of customer contributions. This means that even a small percentage saving in investment costs as a result of more efficient charging signals would deliver benefits of multiple millions of pounds; and
- proposals to implement changes to the way DNOs charge IDNOs which provides potential competition benefits.

Options

1.12. Following the implementation of the licence requirement on DNOs to implement a common methodology at lower voltage levels from 1 April 2010, the licence specifies that the Authority is now allowed to approve the DNOs' proposals for implementation in April 2010, veto them or to approve them subject to conditions.

1.13. The impact on customers of the changes is discussed in more detail below. Given these impacts we have considered the option of phasing in the charges that result from the common methodology. The impact of phasing would be to limit the annual changes in charges for customers. This could benefit key customer groups, for example suppliers that serve niche customers. On balance we do not consider phasing to be appropriate because:

- it is unclear how to consistently apply phasing within the CDCM: capping or collaring charges would arbitrarily distort charging outputs;
- any phasing is likely to dilute the cost reflectivity and transparency of the charges emanating from the common methodology over a period of time, potentially a number of years. When we decided to require DNOs to implement a common methodology in 2008 a key determinant for this was that transparency would drive benefits for consumers;
- we do not consider that cross subsidies are beneficial to customers at large; and
- phasing would make subsequent modifications to the methodology under open governance arrangements more difficult as these would need to take account of any phasing arrangements, making it difficult for those putting forward modifications to set out how charges would change as a result of the proposal and introducing distortions in to the model for those assessing modifications.

1.14. In coming to our conclusion that it would not be appropriate to phase charges we have also considered what mitigating factors are available to customers to manage the changes in charges. We consider that whilst the impacts are larger than normal year on year changes, these have been signalled in advance to customers:

- charging impacts have been published through the project, and whilst the charges submitted to us are different from those presented in June and July, there is visibility of these illustrative charges six months prior to them taking effect. Whilst the impact of the final price control settlement is not yet known, these charges have been produced well in advance of the three month notice period normally provided in respect of charge changes;
- suppliers pay use of system charges on behalf of the vast majority of customers. We, and the industry, have signalled the impact of both this project and the price control over time and therefore anticipate that the risk on suppliers of customers taking fixed term contracts covering charges after 2010 is lower than at other times as suppliers would be expected to be taking steps to limit their exposure to these charge changes at this time; and
- DNOs have generally undertaken to carry out specific communications strategies at this time to help them serve their customers. We reiterate they will need to engage with specific customer groups where charges are expected to increase,

for example some DNOs will need to talk to councils regarding unmetered supply tariffs, to ensure they have visibility of the changes at the earliest opportunity.

Impacts on customers

1.15. The move by DNOs to a common methodology has some large one-off impacts on demand and generation customers as well as on IDNO charges. Appendix C to the DNOs' CDCM submission provides illustrative tariffs for each DNO area together with the impact on demand customers' bills that would have resulted from the application of the CDCM in 2009/2010. Table 8 below extends this analysis to consider the joint impact of the CDCM and the start of the next (DPCR5) price control. The price control has not been concluded and these figures are therefore illustrative at this stage; we will provide further figures as part of our price control final proposals document.

Charges to demand customers

1.16. At a high level, the approach being adopted for demand customers is broadly similar to the existing approach for the majority of DNOs - cost allocation is based on the contribution of each customer group to simultaneous maximum load. However, some important changes have been implemented that can have a large impact on charges. These include:

- changes to the way coincidence factors are calculated;
- changes to the way costs are allocated into fixed and capacity charge: namely, the allocation of costs to into fixed and capacity charge is through the application of standing charge parameters without regard to contribution to simultaneous maximum load;
- changes to the revenue matching approach; and
- changes to the design of the network (500MW) model. Namely, harmonisation of principles.

1.17. The actual charge disturbance will depend on many factors, not least on the departure of the CDCM from a DNO's current methodology. Other details have also been further developed or modified from current methodologies and will contribute to the impact on charges. The key issues are discussed in Chapter 2.

1.18. The impact of the new methodology on charges for demand customers is set out in tables 7 and 8 below. Table 7 draws on illustrative charges from the DNOs' CDCM submission, which uses 2009/10 charging parameters throughout. Table 8 factors in estimated annual change to allowed revenue as set out in our price control Initial Proposals paper and presents the associated illustrative impact on charges.

1.19. In addition to the average change per customer group per DNO area, the tables present overall (non-weighted) average impacts on use of system charges and on end customer bills under the simplifying assumption that these charges comprise

20% of final annual electricity bills. Due to the high variability across DNO areas these average figures should be interpreted with caution.

1.20. Domestic customers represent 90% of meter points (MPANs), and more than three quarters of these represent customers on a domestic unrestricted (i.e. one unit rate) tariff. Across DNOs an average domestic unrestricted customer will see their use of system charges increase, however there are falls in charges across three DNO areas. Translated into final bills the average movement on a current year basis is less than 1%, albeit it is slightly higher when the expected impact of the new price control is taken in to account.

Table 7 - Illustrative percentage impact of the CDCM on average customer[1] distribution use of system charge bills on a 2009/10 charging basis

	CE NEDL	CE YEDL	CN East	CN West	EDF EPN	EDF LPN	EDF SPN
Domestic Unrestricted	-7.5	-12.1	10.9	5.9	-2.2	1.2	14.2
Domestic Two Rate	-11.0	-16.6	6.0	-5.9	3.4	-3.6	0.2
Domestic Off Peak (related MPAN)	-50.6	-35.7	74.9	-58.7	-76.3	-40.1	-45.3
Small Non Domestic Unrestricted	-12.8	-13.1	-9.0	-12.0	-7.2	-32.8	-13.7
Small Non Domestic Two Rate	-12.2	-6.0	6.8	-12.6	4.7	-47.9	-9.7
Small Non Domestic Off Peak (related MPAN)	-29.9	30.5	-19.4	-36.1	-73.2	-42.2	-52.9
LV Medium Non-Domestic	-5.9	-1.6	-12.6	-22.9	-13.8	-24.3	-34.0
LV Sub Medium Non-Domestic	30.3						
HV Medium Non-Domestic	72.8	55.6	-15.1	-26.6			
LV HH Metered	8.9	12.5	-17.6	-5.8	-20.9	11.8	-23.0
LV Sub HH Metered		23.8			18.0		
HV HH Metered	60.3	51.3	-0.3	11.2	23.4	25.3	33.5
HV Sub HH Metered		119.2					
NHH UMS	65.5	5.6	1.9	4.6	10.7	-3.2	-11.1
LV UMS (Pseudo HH Metered)	53.3	-3.0	1.7	-3.7	3.8	37.4	38.8

	ENW	SP Dist	SP Manweb	SSE Hydro	SSE Southern	WPD Wales	WPD West
Domestic Unrestricted	9.5	3.3	6.1	3.7	0.1	3.1	5.8
Domestic Two Rate	12.6	-5.7	-9.8	39.4	-4.4	-0.3	-2.3
Domestic Off Peak (related MPAN)	-41.2	-22.3	-80.3	10.5	-3.7	-47.6	-66.0
Small Non Domestic Unrestricted	-10.1	-13.3	-9.5	-30.3	-18.9	-1.7	7.7
Small Non Domestic Two Rate	31.7	-35.4	-7.5	-15.8	-12.4	-11.4	-25.7
Small Non Domestic Off Peak (related MPAN)		-76.1	-83.4	-13.4	-24.5	-54.6	-42.1
LV Medium Non-Domestic	-29.0	-27.2	-2.2	-5.4	-32.2	-30.8	-35.3
LV Sub Medium Non-Domestic	-26.8		-9.4				-21.1
HV Medium Non-Domestic	-64.7	-62.3	-47.0	-8.3	-51.5	-49.8	-57.2
LV HH Metered	-15.4	9.1	4.9	-5.2	7.4	-14.3	-14.3
LV Sub HH Metered	-0.6		15.9				3.5
HV HH Metered	-14.0	47.7	-10.6	33.5	31.8	24.7	20.8
HV Sub HH Metered	-21.7		-2.4				
NHH UMS	138.6	1.0	-15.8	40.3	44.6	-1.4	-12.5
LV UMS (Pseudo HH Metered)	61.8		-17.1		42.0	-10.0	-8.9

	Average impact on DUoS charge	Average impact on end customer bill[2]	MPANs
Domestic Unrestricted	3.0	0.6	1528206 (73.1)
Domestic Two Rate	0.1	0.0	351922 (16.8)
Domestic Off Peak (related MPAN)	-34.4	-6.9	34485 (1.6)
Small Non Domestic Unrestricted	-12.6	-2.5	117319 (5.6)
Small Non Domestic Two Rate	-11.0	-2.2	32693 (1.6)
Small Non Domestic Off Peak (related MPAN)	-39.8	-8.0	4320 (0.2)
LV Medium Non-Domestic	-19.8	-4.0	11259 (0.5)
LV Sub Medium Non-Domestic	-6.8	-1.4	987 (0)
HV Medium Non-Domestic	-23.1	-4.6	80 (0)
LV HH Metered	-4.4	-0.9	5323 (0.3)
LV Sub HH Metered	12.1	2.4	1172 (0.1)
HV HH Metered	24.2	4.8	1417 (0.1)
HV Sub HH Metered	31.7	6.3	99 (0)
NHH UMS	19.2	3.8	2384 (0.1)
LV UMS (Pseudo HH Metered)	16.3	3.3	18 (0)

Notes:
1) Assumed average consumption per user group may differ across DNOs.
2) We assume that DUoS charge comprises 20 per cent of end customer bill.

Table 8 - Illustrative percentage impact of the CDCM on average customer[1] distribution use of system charge bill taking in to account initial price control proposals[3]

	NEDL	YEDL	CNE	CNW	EPN	LPN	SPN
Domestic Unrestricted	-1.5	-7.5	16.0	10.9	2.5	8.2	23.8
Domestic Two Rate	-4.9	-12.0	11.3	-1.3	8.7	3.0	8.9
Domestic Off Peak (related MPAN)	-48.7	-33.5	82.4	-58.0	-75.8	-36.8	-40.0
Small Non Domestic Unrestricted	-6.6	-8.1	-4.5	-7.4	-1.8	-27.7	-5.7
Small Non Domestic Two Rate	-6.0	-0.7	12.1	-8.1	10.6	-43.7	-1.0
Small Non Domestic Off Peak (related MPAN)	-26.2	36.8	-16.2	-33.6	-72.6	-38.8	-48.9
LV Medium Non-Domestic	0.7	3.8	-8.4	-18.9	-8.9	-18.9	-27.6
LV Sub Medium Non-Domestic	39.5						
HV Medium Non-Domestic	85.9	64.9	-10.8	-22.8			
LV HH Metered	16.4	18.4	-14.0	-1.9	-17.2	19.7	-16.8
LV Sub HH Metered		30.3			23.8		
HV HH Metered	73.4	61.2	5.1	16.7	30.2	33.7	45.7
HV Sub HH Metered		133.7					
NHH UMS	77.8	11.8	6.1	8.7	15.0	2.4	-5.3
LV UMS (Pseudo HH Metered)	65.3	3.1	6.4	0.2	7.7	44.8	47.5

	ENW	SP Dist	SP Manweb	SSE Hydro	SSE Southern	WPD Wales	WPD West
Domestic Unrestricted	16.6	-0.9	14.5	8.2	7.2	8.1	12.1
Domestic Two Rate	20.2	-9.7	-2.4	46.4	2.7	4.6	3.7
Domestic Off Peak (related MPAN)	-39.8	-25.4	-79.7	16.2	0.0	-45.8	-65.2
Small Non Domestic Unrestricted	-3.5	-17.2	-1.7	-26.9	-12.8	3.3	14.6
Small Non Domestic Two Rate	40.6	-38.2	0.5	-11.6	-6.0	-6.9	-20.9
Small Non Domestic Off Peak (related MPAN)		-77.0	-83.0	-8.9	-20.1	-53.1	-39.8
LV Medium Non-Domestic	-23.9	-30.5	6.2	-0.9	-27.3	-27.3	-31.2
LV Sub Medium Non-Domestic	-21.1		-1.2				-15.7
HV Medium Non-Domestic	-61.5	-64.1	-41.4	-4.1	-48.5	-47.0	-54.6
LV HH Metered	-11.0	4.6	13.3	-1.3	14.0	-10.3	-9.2
LV Sub HH Metered	5.9		24.9				10.0
HV HH Metered	-4.6	41.1	-1.4	38.7	40.4	32.0	29.3
HV Sub HH Metered	-7.9		10.2				
NHH UMS	145.7	-2.9	-9.7	45.8	53.6	3.2	-7.2
LV UMS (Pseudo HH Metered)	66.5		-11.1		51.1	-5.5	-3.6

	Average impact on DUoS charge	Average impact on end customer bill[2]	MPANs
Domestic Unrestricted	8.4	1.7	1528206 (73.1%)
Domestic Two Rate	5.7	1.1	351922 (16.8%)
Domestic Off Peak (related MPAN)	-32.1	-6.4	34485 (1.7%)
Small Non Domestic Unrestricted	-7.6	-1.5	117319 (5.6%)
Small Non Domestic Two Rate	-5.7	-1.1	32693 (1.6%)
Small Non Domestic Off Peak (related MPAN)	-37.0	-7.4	4320 (0.2%)
LV Medium Non-Domestic	-15.2	-3.0	11259 (0.5%)
LV Sub Medium Non-Domestic	0.3	0.1	987 (0%)
HV Medium Non-Domestic	-18.5	-3.7	80 (0%)
LV HH Metered	0.3	0.1	5323 (0.3%)
LV Sub HH Metered	19.0	3.8	1172 (0%)
HV HH Metered	31.5	6.3	1417 (0.1%)
HV Sub HH Metered	45.4	9.1	99 (0%)
NHH UMS	24.6	4.9	2384 (0.1%)
LV UMS (Pseudo HH Metered)	22.7	4.5	18 (0%)

Notes:
1) Assumed average consumption per user group may differ across DNOs.
2) We assume that DUoS charge comprises 20 per cent of end customer bill.
3) Based on Initial Proposals allowed revenue adjustment estimates. Over/under recovery is not considered.

1.21. We note that some of the ranges of charge movements are relatively large, even after taking account that distribution charges generally comprise less than 20% of a customers' bill. As set out in Appendix A to their CDCM submission to us, responses to the DNOs' consultations in the summer suggested some (particularly smaller) suppliers favoured the phasing of charges. DNOs' response to concerns from these specific suppliers has been that the models presented to the suppliers have since changed and that the impacts on small and medium sized enterprise customers, who are often served by small suppliers, are now reduced.

1.22. We note that suppliers can choose how to pass on use of system charges to their customers. Suppliers with a non-diversified portfolio of customers (niche suppliers) are expected to be impacted more than diversified suppliers as, for the latter, the impact on domestic bills (which make up 90% of MPANs) is likely to dwarf the larger impacts on other customers. Such niche suppliers and their customers can be expected to be impacted further and we expect DNOs to do all they can to ensure suppliers are aware of the likely changes in charges from April 2010.

Charges to generators

1.23. Under current price control arrangements generation use of system charges are set to recover a positive amount of allowed generation revenue. This implies that generation charges are, on average, positive. Under the CDCM proposals charges to generators are not scaled the average generator customer (in fact, nearly all exporting generators) will receive a credit, so long as the network is assumed to be demand dominated. Generators can therefore expect to see a reduction in their total energy bill. To illustrate the impact on tariffs, table 9 below presents current versus CDCM proposed generator charges for LV non half hourly generators in ENW's area.

1.24. The cost of applying the new generator charging approach across DNOs and suppliers is expected to be minimal: they have not been flagged as significant in

DNOs' earlier consultations on the common methodology or in responses to the consultations.

Table 9 - Illustrative impact of new generator charging approach in ENW's area: LV NHH customers

	Unit rate (p/kwh)
Current 2009/10 charge	0.391
Illustrative new CDCM charge	-0.664

Charges to IDNOs

1.25. The common method proposes IDNO-specific tariffs be levied on charges to IDNOs on the basis that IDNO-specific charging is necessary. We have urged action on this matter for a number of years and have consulted on IDNO-specific tariffs multiple times in relation to DNO-specific proposals to us. We consider that the benefits of such an approach outweigh the costs. The common method brings all DNOs in to line on this matter. The impact of the CDCM on charges to IDNOs is set out in tables 10 to 12. For completeness, table 4 from Chapter 2 is replicated below.

Table 4 (replica) – Illustrative comparison of current and proposed CDCM IDNO margins for domestic unrestricted customers connected to the LV tier

CDCM IDNO Discount		CDCM ATW bill	Proposed margin	Current Margin		
Dom UR	LV	Dom UR	All plots	25 plots	50 plots	100 plots
CN East	26.9%	£64.45	£17.34	£21.76	£15.30	£25.65
CN West	28.7%	£66.31	£19.03	£23.80	£18.00	£33.31
CE NEDL	37.4%	£66.77	£24.97	£21.55	£28.58	£27.33
CE YEDL	35.2%	£59.50	£20.94	£15.63	£24.42	£30.54
EDF EPN	18.8%	£62.95	£11.83	£9.75	£22.81	£5.20
EDF LPN	18.7%	£62.40	£11.67	(£7.61)	(£2.76)	£14.76
EDF SPN	20.9%	£64.73	£13.53	(£5.62)	£9.09	(£0.42)
ENW	30.2%	£73.30	£22.14	£11.34	£17.59	£20.28
SP Distribution	30.4%	£95.09	£28.91	£21.33	£27.73	£30.93
SP Manweb	31.9%	£85.89	£27.40	£21.33	£27.38	£29.61
SSE Southern	31.6%	£81.34	£25.70	£23.67	£27.50	£29.42
SSE Hydro	24.8%	£118.85	£29.47	£33.96	£34.79	£35.21
WPD West	34.1%	£94.75	£32.31	£21.18	£21.18	£21.18
WPD Wales	28.8%	£95.88	£27.61	£27.98	£27.98	£27.98

Table 10 - Illustrative comparison of current and proposed CDCM IDNO margins for domestic Economy 7 customers connected to the LV tier

CDCM IDNO Discount		CDCM ATW bill	Proposed margin	Current Margin		
Dom E7	LV	Dom E7	All plots	25 plots	50 plots	100 plots
CN East	26.9%	£72.62	£19.53	£8.36	£3.80	£9.71
CN West	28.7%	£69.41	£19.92	£10.96	£14.46	£20.64
CE NEDL	37.4%	£76.13	£28.47	£22.87	£29.91	£12.78
CE YEDL	35.2%	£66.32	£23.34	£20.23	£29.02	£10.05
EDF EPN	18.8%	£72.41	£13.61	£11.63	£24.69	£11.96
EDF LPN	18.7%	£73.64	£13.77	(£12.62)	(£7.77)	£9.74
EDF SPN	20.9%	£67.82	£14.17	£9.74	£24.44	£14.94
ENW	30.2%	£79.44	£23.99	£19.57	£8.38	£18.61
SP Distribution	30.4%	£111.30	£33.84	£38.21	£44.61	£47.81
SP Manweb	31.9%	£98.80	£31.52	£38.21	£41.43	£43.67
SSE Southern	31.6%	£73.69	£23.29	(£24.47)	(£19.08)	(£14.05)
SSE Hydro	24.8%	£214.36	£53.16	£30.71	£31.54	£31.96
WPD West	34.1%	£116.08	£39.58	£21.98	£21.98	£21.98
WPD Wales	28.8%	£125.51	£36.15	£27.98	£27.98	£27.98

Table 11 - Illustrative comparison of current and proposed CDCM IDNO margins for domestic unrestricted customers connected to the HV tier

CDCM IDNO Discount		CDCM ATW bill	Proposed margin	Current Margin	
Dom UR	HV	Dom UR	All plots	100 plots	200 plots
CN East	36.4%	£64.45	£23.46	£21.74	£29.60
CN West	40.0%	£66.31	£26.52	£28.74	£36.97
CE NEDL	50.4%	£66.77	£33.65	(£9.23)	£24.86
CE YEDL	49.5%	£59.50	£29.45	£0.34	£27.18
EDF EPN	27.4%	£62.95	£17.25	£41.95	£45.20
EDF LPN	30.8%	£62.40	£19.22	£41.35	£44.83
EDF SPN	30.8%	£64.73	£19.94	(£0.42)	£3.24
ENW	47.5%	£73.30	£34.82	n/a	£26.10
SP Distribution	42.0%	£95.09	£39.94	£30.35	£44.13
SP Manweb	44.1%	£85.89	£37.88	£22.93	£31.98
SSE Southern	40.4%	£81.34	£32.86	£30.28	£36.58
SSE Hydro	31.3%	£118.85	£37.20	£53.34	£54.78
WPD West	45.8%	£94.75	£43.40	£44.70	£44.70
WPD Wales	42.0%	£95.88	£40.27	£42.86	£42.86

Table 12 - Illustrative comparison of current and proposed CDCM IDNO margins for domestic Economy 7 customers connected to the HV tier

CDCM IDNO Discount		CDCM ATW bill	Proposed margin	Current Margin	
Dom E7	HV	Dom E7	All plots	100 plots	200 plots
CN East	36.4%	£72.62	£26.43	£10.66	£18.52
CN West	40.0%	£69.41	£27.76	£20.98	£29.21
CE NEDL	50.4%	£76.13	£38.37	(£13.59)	£20.50
CE YEDL	49.5%	£66.32	£32.83	(£7.45)	£19.36
EDF EPN	27.4%	£72.41	£19.84	£48.71	£51.96
EDF LPN	30.8%	£73.64	£22.68	£36.32	£39.82
EDF SPN	30.8%	£67.82	£20.89	£14.94	£14.60
ENW	47.5%	£79.44	£37.73	£19.56	£29.50
SP Distribution	42.0%	£111.30	£46.75	£48.68	£62.46
SP Manweb	44.1%	£98.80	£43.57	£40.96	£50.01
SSE Southern	40.4%	£73.69	£29.77	£22.79	£29.10
SSE Hydro	31.3%	£214.36	£67.09	£66.05	£67.44
WPD West	45.8%	£116.08	£53.16	£45.50	£45.50
WPD Wales	42.0%	£125.51	£57.48	£50.46	£50.46

Impacts on competition (including effects on small businesses)

1.26. A common and transparent charging methodology for all DNOs is expected to reduce barriers to entry for new suppliers. It will allow greater certainty and understanding of the way in which charges are calculated which will aid competition within the electricity industry.

1.27. Suppliers who specialise in serving small business customers will see charges falling across most DNO areas which is not expected to adversely impact on competition. Those suppliers that serve larger half hourly connected customers see a higher average increase in bills. With advance notice our expectation is that these expected changes will filter in to the contracts suppliers offer their customers and we would expect the impact on competition to be negligible. In addition, all suppliers have the same information available to them, and therefore we do not consider there will be significant adverse effects on competition in supply.

1.28. The impact of the proposed introduction of IDNO-specific tariffs and common methodology across DNOs should be to aid competition for the distribution of electricity as under the proposal there is clear certainty and consistency in respect of the margins. Moreover, the margins available to IDNOs are generally increasing and negative margins are eliminated.

1.29. The likely impact on competition of (generally) non-negative charges across all generators from April 2010 appears to be a non-discriminatory application of use of system charging for generators and as such could be expected to improve competition in the generation sector against the current position.

Impacts on sustainable development

1.30. A qualitative evaluation of the proposals submitted by the DNOs suggests that providing a credit to generators will provide an incentive to connect distributed generation. The implementation of common red, amber and green tariff rates for half hourly metered customers can be expected to encourage users to switch consumption away from peak (red) time usage to other time periods since peak rates are much higher than other rates, thereby reducting future network costs.

Risks and unintended consequences

1.31. We note that the use of an average charging model approach could lead to charges in specific locations at lower voltages being inappropriate. For example, credits could be paid to generators where they impose a cost on the distribution network. We expect DNOs to further develop their thinking in this area for 1 September 2010, as set out in our minded to conditional approval on this matter.

1.32. The approach at lower voltages has always been to charge via an average cost (yardstick) at each voltage/transformation level adjusted by the profile of consumption for customers without half hourly metering. We note that an individual's consumption may not match that of the aggregate profile, particularly an individual domestic customer. Given improvements in computer processing power and the timetable for the roll out of smart meters we have every expectation that this approach will be further refined in the future.

1.33. Another risk we have noted concerns the input costs used by individual DNOs and the extent to which these inputs are appropriate. The inputs used have an impact on the level of matching required to achieve allowed revenue which in turn has an impact on customer charges. We have asked for inputs to be considered further by the industry via open governance arrangements.

Impacts on health and safety

1.34. We are not aware that these proposals have any significant impacts on health and safety.

Other impacts (including implementation costs)

1.35. Implementing the proposals at lower voltages will cost DNOs and suppliers money in terms of changes required to billing systems. DNOs have previously indicated that the costs could be in the region of £0.5m per DNO group, and we have discussed with DNOs tying billing system change timescales to other changes in billing systems to maximise efficiency. We have asked DNOs to engage with us as a matter of urgency if this means that billing systems will not be in place in time to implement the common methodology from 1 April 2010. We consider that these impacts are outweighed by the expected benefits from the project over time in terms of increased transparency to suppliers (reducing their need to charge a premium to cover the risk of changes in charges).

1.36. There will also be consequential impacts on the costs of setting up processes to manage the common methodology over time. These costs are expected to be minimal against the benefits of a common approach suggested by stakeholders (particularly suppliers) during the consultation phase of the project.

1.37. Future impacts of the new methodology on tariffs concern areas where we have issued conditional approvals. The risk with conditional approvals is that charges will move further from those that are already visible to customers. We expect DNOs to keep customers informed of any changes and, where they are significant, to give adequate prior notice of the change. We are minded to conditionally approve with a timescale for delivery in time for April 2010 charges in two areas where we consider there has been (i) an error and (ii) an omission from the methodology and these changes would have a negligible impact on charges. The third area we are minded to conditionally approve is where we do not consider that the DNOs have gone far enough in considering how to charge generators where the network is generation dominated. We have given the DNOs a timescale for delivery of 1 September 2010 for considering this issue further and for bringing forward any required changes to the CDCM. Any resulting changes to the model will have an impact on customer charges. DNOs will need to clearly set out the potential impacts on charges for our, and the industry's, consideration. We would expect that the publication of each DNO's common model will enable users to ask questions of DNOs and to understand themselves more fully the mechanics of the model.

Post implementation review

1.38. We intend to monitor the impact of the proposal once it is implemented via the ongoing forum that DNOs are required to set up to discuss changes to the methodology[32] as well as via our links with consumers and consumer interest groups. Parties that are materially affected by charges will be allowed to raise changes to the methodology through DCUSA-based open governance arrangements, which will allow for changes over time should they be deemed necessary. The volume of these changes will to some extent allow us to monitor how parties have reacted to the new common methodology and its associated impacts on charges.

[32] Our current understanding is that this will be captured under the existing electricity distribution charging methodologies forum (DCMF). The DCMF's work can be viewed on the Energy Network Association's website at http://2009.energynetworks.org/distribution-charging-methodol/.

Conclusion

1.39. The DNOs have brought forward a common methodology as required by their licence. As set out in Chapter 2, and considering the matters set out in this impact assessment we are minded to approve the DNOs' common charging model subject to a limited number of conditions. We seek views on our 'minded to' decisions on these conditions and to understand whether there are any other issues that respondents wish to raise with respect to our impact assessment. The common model would then form a baseline from which conditional approval points can be delivered on and the common arrangements can be progressed through open governance arrangements.

1.40. The illustrative impact of the new methodology on end customer bills for two-thirds of customers (domestic customers subject to a single unit rate tariff) is in the range -2% to +5%, based on assumptions that will change once the final price control proposals and DNOs' under and over recovery revenue positions are known. As set out above we consider that on balance the costs of phasing such changes outweighs the benefits of such an approach. We also consider that some elements of the charge movements warrant further work by DNOs, as set out in our areas for further work and our decisions on areas where we are minded to approve the common methodology subject to formal conditions regarding further work.

Appendix 4 - The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts[33].

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[34].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of existing and future consumers, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- the need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- the need to secure that all reasonable demands for electricity are met;
- the need to secure that licence holders are able to finance the activities which are the subject of obligations on them[35];
- the need to contribute to the achievement of sustainable development; and
- the interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas[36].

[33] entitled "Gas Supply" and "Electricity Supply" respectively.
[34] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[35] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.
[36] The Authority may have regard to other descriptions of consumers.

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- promote efficiency and economy on the part of those licensed[37] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity; and
- secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- the effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- the principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[38] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

[37] or persons authorised by exemptions to carry on any activity.
[38] Council Regulation (EC) 1/2003.

Appendix 5 - Glossary

A

Authority

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

C

Common Distribution Charging Methodology (CDCM)

The common methodology for HV/LV charging as developed and submitted by the DNOs on 25 August 2009 for approval by the Authority under standard licence condition 50.

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 HV/LV charging.

D

Distribution Connection and Use of System Agreement (DCUSA)

The DCUSA is an industry code which governs connection and use of system arrangements between DNOs, suppliers and some generators on the distribution networks.

Distributed Generation (DG)

Generation which is connected directly into the local distribution network as opposed to the transmission network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transmitted for use across Great Britain.

Distribution Network Operators (DNOs)

A licensed distributor which operates electricity distribution networks in distribution service areas but can also compete to operate networks anywhere within Great Britain.

Distribution Price Control Review 5 (DPCR5)

DNOs operate under a price control regime, which are 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 typically lasts five years at a time. The existing price control (DPCR4) will expire 31 March 2010. DPCR5 is planned to commence on 1 April 2010.

Distribution Reinforcement Model (DRM)

A methodology for the formulation of use of system charges for the distribution network. The approach uses a representative model of the network for establishing use of system tariffs.

Distribution Service Area (DSA)

As defined in SLC 1 of the electricity distribution licence.

E

Electricity Act 1989

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

Engineering Recommendation 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 consisting of a voltage level of 22kV or more.

F

Forecast Business Plan Questionnaire (FBPQ)

Forecast Business Plan Questionnaires are submitted by DNOs as part of the DCPR5 process. FBPQs contain the details of companies forecast expenditure over the period covered by the DCPR5 settlement. The FBPQs also contain details of historic expenditure over the DCPR4 price control period.

G

Grid Supply Point (GSP)

A Grid Supply Point is any point at which electricity is delivered from the National Electricity Transmission System to the DNO's Distribution System.

H

Half hourly (HH) metered customers

Customers with a metering system which provides measurements on a half hourly basis for settlement purposes.

HV/LV – High/Low Voltage

Term used to describe the parts of the distribution networks typically at a voltage level of less than 22kV.

I

Independent Distribution Network Operators (IDNOs)

A licensed distributor which does not have a distribution services area and competes to operate electricity distribution networks anywhere within Great Britain.

L

Licensed Distribution Network Operators (LDNOs)

A term that captures both IDNOs and DNOs operating networks outside their distribution services areas.

M

Modern Equivalent Asset Value (MEAV)

The cost of the network using current ('modern equivalent') assets and their associated current costs.

N

Non half hourly (NHH) metered customers

Customer with a metering system that does not provide measurements on a half hourly basis but rather total consumption to date at time of reading. Settlement is based on profiling data.

S

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.

T

Transmission exit charges

Transmission exit charges are charges paid by DNOs to National Grid (in its role as GB System Operator) for the financing and operating costs of the assets that connect the distribution network to the transmission network (the transmission exit point).

U

Use of System (UoS) Charges

Use of System Charges: Charges paid by generators and suppliers for the use of the distribution network.

Appendix 6 - 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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