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Delivering the electricity distribution structure of charges project

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

Overview:

This document sets out our decision on the common methodology and governance arrangements that should apply to electricity distribution use of system charges across GB from April 2010. In parallel we are publishing a statutory notice of the licence modifications required to implement the new arrangements. Electricity distribution licence holders have 28 days to decide whether or not to accept these proposed licence modifications.

If sufficient licensees accept the modifications, all electricity distribution network operators will be required from April 2010 to set charges according to the same methodology. The common methodology aims to contain price increases by encouraging efficient network development, and to tackle climate change by rewarding distributed generation and demand side management where these bring network benefits. The proposed governance arrangements allow all users to bring forward change proposals to ensure the methodology continues to achieve these objectives and facilitate effective competition from independent network operators.

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Context

For several years Ofgem has been trying to make the electricity distribution network operators (DNOs) introduce new charging methodologies. There has been limited progress on this front despite a number of DNOs bringing forward proposed modifications to their methodologies.

If accepted, the licence modification proposals published alongside this document will require all 14 DNOs in Great Britain to charge according to a common methodology. The methodology would be a significant step forward in introducing more cost reflective charges that recognise the benefits that distributed generation and demand side management may bring. Importantly, the modifications would also introduce new governance arrangements that allow all users to influence the direction and pace at which this methodology develops and evolves in future.

The proposed arrangements are timed to come into effect at the beginning of the next price control period which starts in April 2010. DNOs tell us they will need to make very significant investment in their networks from 2010 to 2015 and that a good proportion of this is due to load growth. In this context, and given the significant recent rises in energy prices and fuel poverty, it is essential that charging arrangements encourage more local generation to connect where it will reduce the need for expensive investment in additional network capacity. It is also important that the charges encourage significant new loads, who have some flexibility over where they locate (for example IT data centres) to locate where spare capacity already exists or away from parts of the network where it will be more expensive to connect them. New charging arrangements are vital if DNOs are to play a leading role in tackling climate change by attracting more distributed generation and encouraging more demand side management.

The proposals in this document are the outcome of a long debate on charging methodologies within the industry. We have formulated these proposals and the process by which the new arrangements will come into effect after extensive formal and informal consultation this year. This project runs in parallel to our wider industry codes governance review. Ultimately, proposals from that review may supersede the governance arrangements set out in this document.

Associated Documents

- Code Governance Review: Charging methodology governance options, 132/08, September 2008
http://www.ofgem.gov.uk/Licensing/IndCodes/CGR/Documents1/CGR_CM_Sept_FINAL.pdf

- Decision in relation to SP's proposal to modify its electricity distribution use of system charging model, September 2008
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=501&refer=Networks/ElecDist/Policy/DistChrgMods

- Decision in relation to EDF's proposal to modify its electricity distribution use of system charging model, September 2008
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=503&refer=Networks/ElecDist/Policy/DistChrgMods

- Decision in relation to SP's proposal to modify its electricity distribution use of system charges for IDNO networks, August 2008
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=483&refer=Networks/ElecDist/Policy/DistChrgMods

- Delivering the electricity distribution structure of charges project: decision on a common methodology for use of system charges, consultation on the methodology to be applied across DNOs, and consultation on governance arrangements, 104/08, July 2008
http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=421&refer=Networks/ElecDist/Policy/DistChrgs

- Delivering the electricity distribution structure of charges project, 36/08, April 2008
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/Sof%20C%20Project%203608.pdf

- Electricity distribution price control review initial consultation document, 32/08, March 2008
http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Documents1/Initial%20consultation%20document.pdf

- Distributed energy - initial proposals for more flexible market and licensing arrangements, 295/07, December 2007
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Documents1/DE%20con%20doc%20-%20complete%20draft%20v3%20141207.pdf

- DNOs' current use of system charging methodologies
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx

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Summary

For several years Ofgem has been trying to make the electricity distribution network operators (DNOs) introduce new charging methodologies. These would encourage much more efficient development of their networks and more local generation to help tackle climate change. They would also facilitate competition with independent network operators (IDNOs) where they are more efficient and/or able to provide better service and faster connections. The DNOs have missed several deadlines and have made limited progress. In the meantime it has become clear that because DNOs all have different charging arrangements there is additional complexity and cost for suppliers, generators and customers that operate across a number of areas.

In July, and after consultation, we decided the best way to make progress was to require by licence all DNOs to adopt a common charging methodology from April 2010. In this document we now set out (1) our final, detailed decision on the proposed common charging methodology and our reasons for reaching that decision; (2) our proposed governance arrangements for the new charging methodology; and (3) how we intend to implement these new arrangements.

There has been a long running debate in the industry as to the most appropriate charging methodology, particularly at extra high voltage (EHV). There is still no agreement between DNOs and for this reason we have made a decision on the models that will form the foundation for the new common methodology. Our decision is for the new common methodology to be based on a long run incremental cost model (LRIC) at EHV level. We believe that LRIC presents the most appropriate model that has been developed for EHV at this time. A methodology based on LRIC will allow DNOs to put in place a charging methodology that promotes the efficient use of the distribution networks in time for the next price control period that starts in April 2010. DNOs expect that they will need to invest very significant sums of money in their networks from 2010 to 2015 and a major driver is deep reinforcement required to accommodate load growth. In this context, and given rising energy prices and fuel poverty, it is essential that distribution charges are structured to encourage new large loads, such as data centres, to locate where there is spare network capacity rather than where capacity is scarce.

We note and accept some of the concerns raised about the use of LRIC, for example concerning potential volatility from year to year in charges. We set out a range of measures that DNOs will have to implement to provide customers, generators and suppliers with information and tools to understand and manage any risks associated with charging volatility under the new methodology. In particular, as a minimum and ahead of April 2010, we will require DNOs to publish their charging models on their websites and to publish annually long term tariff scenarios to help customers understand the range of future charges. Within one year, we expect DNOs to develop and bring forward proposals for longer term products that would offer generators and customers the choice of fixing their nework charges in return for making a long term commitment to pay them, to help customers to manage the risk of charging volatility. DNOs could also consider more sophisticated web based tools for application post April 2010. We also recognise that in certain, limited circumstances the LRIC approach can give rise to anomalous, non cost-reflective

charges at particular locations on the network. DNOs will need to carefully "sense check" the outputs of the new methodology and propose suitable alternative arrangements based on their best assessment of the long run incremental cost of providing capacity at that point on their network. We would consider issuing guidance or introducing further detail into the methodology on this issue if DNOs would find it helpful. But we stress that ultimately it is for DNOs, consistent with their legal obligations, to determine whether it would be appropriate to make adjustments to the outputs of the LRIC methodology at certain locations and to be able to justify any amendments they make. DNOs will have to publish a clear explanation of the reasons for any adjustments and why they deliver more cost reflective charges at that location.

The common methodology will contain a distribution reinforcement model (DRM) for high/low voltage (HV/LV) demand customers. This reflects the approach applied by the majority of DNOs currently. For HV/LV generation customers an approach mirroring DRM is to be used. This method reflects the benefit that generation can provide to demand dominated networks. Our decision does not set out the methodology that DNOs should apply when setting charges for IDNOs. We expect DNOs to continue to work with IDNOs to develop a common methodology for IDNO charging as soon as possible. We will continue to facilitate this process.

We propose to require DNOs to introduce new governance arrangements for the common methodology that would allow users such as IDNOs, suppliers, distributed generators or customers to raise modifications to the methodology and allow for its ongoing development. We see this as an important safeguard for two reasons. There is no agreement over the most appropriate methodology and these arrangements will allow the common methodology to evolve over time if unforeseen problems emerge. It will also allow parties other than the DNOs to drive changes to the methodology if wider changes in the energy market require them. We think this is necessary given the slow progress that most DNOs have made over the last few years in developing their methodologies.

Timescales in this project are tight and we are committed to doing all we can to ensure that DNOs are able to meet them. We have looked for ways to minimise the need for DNOs to work together ahead of April 2010 and to provide clarity around what successful implementation of the methodology means. DNOs will be required to bring forward charges according to the new methodology by Sept 2009 in time for implementation in April 2010. We will also expect DNOs, as part of the current price control review – to identify what they expect the impact of the new charges to be on their load growth and capital expenditure forecasts for the next five years.

We hope that all, or enough DNO licence holders consent to our proposed CLM. If they do not, we will need to consider whether to refer the matter to the Competition Commission. There is a long history of DNOs missing deadlines and failing to deliver. The new charging methodology will help to promote more efficient network development by reducing the need for significant investment to increase network capacity. It will also play a crucial role in helping distribution companies play their part in tackling climate change though greater use of local generation. Given all of this we would recommend to the Authority referring the matter to the Competition Commission immediately if sufficient DNOs do not consent to the proposed licence changes.

1. Background and rationale for the licence modification proposals

Chapter Summary

In this chapter we set out the high level rationale for the decisions contained in this document and the background to our work on the electricity distribution use of system charging methodologies. We also explain the structure of the remainder of this document.

Rationale for change

1.1. For several years the DNOs have been working to deliver improved methodologies for charging for the use of their networks. With few exceptions, existing methodologies fail to recognise the significant benefits that distributed generation (DG) at lower voltage levels may provide to the network - such as reducing the need to invest in expensive additional capacity. They do not encourage demand side management that could bring the same benefits. In addition improvements are necessary to adequately facilitate competition where independent distribution network operators (IDNOs) are able to provide cheaper or faster connections than the incumbent DNO.

1.2. These problems with the existing methodologies represent a significant barrier to helping to tackle climate change by reducing carbon emissions from the energy sector and also put further pressure on rising energy bills through higher network charges harming all customers but especially the fuel poor.

1.3. Our efforts to implement better charging methodologies have met with limited success because we have relied on DNOs to develop and bring forward proposals to us that we can then either approve or reject. Only one DNO, Western Power Distribution, has developed and implemented a fundamental step change in its methodology and while EDF Energy Networks and SP Energy Networks have put forward proposals we rejected them both as they did not, on balance represent an improvement on the current arrangements[1]. We recognise that some DNOs have held back their substantial modification proposals while waiting for this document.

1.4. In April we published a consultation[2] on how we should take this project forward and said that we thought this project would only succeed if the DNOs were required

[1] The relevant licence objectives require DNOs to ensure that methodologies:
- are cost reflective as far as possible;
- facilitate competition in generation and supply as well as not distorting, preventing or restricting competition in the transmission or distribution of electricity;
- take account of developments in DNOs' distribution businesses as far as is reasonably practicable; and
- facilitate the discharge by DNOs of obligations under the Act and the distribution licence.

[2] April 2008 consultation 'Delivering the electricity distribution structure of charges project', ref 36/08, available on our website along with responses to it. This consultation sets out the

by licence to put in place new charging methodologies by April 2010 (the commencement of the next price control period). This would allow us to take enforcement action and if, necessary and appropriate, to impose financial penalties on DNOs who failed to meet this deadline.

1.5. We think that the plausible range of benefits to suppliers and customers of new charging methodologies are in the order of multiple millions of pounds per year. As part of the current distribution price control review, DNOs have already given an indication of their capital expenditure plans for the next five years. These plans show significant increases in capital expenditure – much of which is related to potential load growth on the network. In total, they are forecasting approximately £5-6bn in load related expenditure. More cost reflective charging could significantly reduce the need for this expenditure – by encouraging more distributed generation to connect and/or encouraging significant new loads such as data centres to locate in other parts of the country or networks where there is surplus capacity. As well as these direct and significant benefits there will also be benefits to suppliers and customers through reduced costs as they will no longer have to analyse and understand a series of different methodologies.

The April 2010 deadline

1.6. We are particularly concerned to get new charging arrangements in place ahead of April 2010 when the new price control period starts. DNOs tell us they will need to make significant investment in deep reinforcement required to accommodate load growth in particular parts of the network. As set out above new charging arrangements could mitigate the need for investment by encouraging new load to locate where there is spare capacity. Given the high investment costs and volumes involved, any small percentage reductions in the level of load related expenditure represent significant savings to customers.

1.7. In addition to the investment drivers, as part of the price control we are considering a range of measures relating to the DNOs' role in facilitating a low carbon economy. As part of the current price control, DNOs are restricted to charging DG based on the revenue provided for through the DG incentive. This approach may restrict the ability of DNOs to pass on the full benefit that DG may provide to their network. We have consulted on whether it is appropriate to remove this restriction as part of DPCR5 and are minded to do so but on the proviso that there are cost reflective DG charging arrangements in place by April 2010. Also as part of DPCR5 we are considering the need for DG connected prior to April 2005 to be charged use of system charges. These generators were exposed to "deep" connection charging arrangements and are currently not exposed to use of system charges. We are concerned that continuing these arrangements, when significant growth in DG is expected, may not promote economic efficiency. In both cases the charging arrangements described in this document are critical items to enable these policy changes to be facilitated.

background to the structure of charges project and explains the various charging elements involved. See website at: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx.

Rationale for a common methodology

1.8. In our July letter we set out that we believed it was appropriate for Ofgem to pick a common methodology and we asked for views on this. There are two main reasons for our decision, set out in July, that DNOs should be required to apply a common charging methodology.

1.9. The first is that the alternative approach - requiring each DNO to introduce a new methodology that meets a set of "relevant principles" - places regulatory risk on the DNOs. Our April document set out for consultation a set of relevant principles against which DNOs should develop their new methodologies. However, it became clear from discussions that various interpretations could be applied to these principles. DNOs had a legitimate concern that they would expend significant effort working up methodologies only for Ofgem to rule that they had not met the principles, they were in breach of a licence condition and could face a financial penalty.

1.10. We have sought to reduce this regulatory risk by setting out in Appendix 2 a detailed methodology that DNOs should apply by April 2010. If the licence modification proposals associated with this document are voted in by DNOs, we will further reduce the regulatory risk on DNOs by working with them to develop a generic template that will represent the charging methodology decisions in this document. Further, we will ensure this template is an appropriate reflection of the common charging methodology before DNOs begin to apply it to their individual networks to develop charges for implementation by April 2010.

1.11. The second reason for requiring a common methodology is the significant net benefits that commonality will bring to suppliers, generators and customers across the country. Responses to our April and July consultations have highlighted the complexity these parties face and the risk premium they pay because of the difficulty associated with understanding how the quantum of their distribution use of system charges are calculated. Suppliers estimate the cost of managing the risk associated with distribution charging arrangements at several millions of pounds a year. This compares with the estimated one-off DNO costs for implementing a common methodology of £0.5 million per DNO group - or a larger sum if changes to billing systems are required. We consider that the costs of implementing a common methodology will quickly be outweighed by the benefits. DNOs would have to bear some of these costs in any case given the further development work required of DNOs to improve their methodologies. The scale of capital expenditure that could be avoided by implementing more cost reflective charges is expected to quickly offset these costs.

1.12. The move to a common methodology will inevitably mean that some DNOs will need to put to one side the work they have conducted to date. However, we do not consider that this work will be entirely wasted and that it could provide important material as DNOs work to improve and develop the common charging methodology. To the extent that DNOs consider the costs they have expended in developing charging methodologies to be material and efficiently incurred, they have the opportunity to make a case for these costs to be recovered through the next price control settlement.

Rationale for new governance arrangements

1.13. We have consulted on the proposal to require DNOs to introduce new governance arrangements for the common methodology that would allow users such as IDNOs, suppliers, distributed generators or customers to raise modifications to the methodology and allow for its ongoing development. Respondents to our July consultation widely supported these proposals.

1.14. We see the new governance arrangements as an essential part of the new arrangements for three reasons. There is no agreement over the most appropriate charging methodology and there is no methodology currently available that clearly provides the best trade off between cost reflectivity on the one hand and stability and transparency, for example, on the other. Governance arrangements will allow the common methodology to evolve and improve over time. It will also allow parties other than the DNOs to drive the pace and direction of changes to the methodology in response to wider changes in the energy market.

1.15. We note the ongoing separate Ofgem review of industry governance arrangements[3]. As set out in more detail in Chapter 5, we consider it appropriate to 'fast-track' DNO governance arrangements as part of this project so that these arrangements apply from 2010. Governance arrangements will therefore need to be developed and submitted to the Authority for approval not later than 1 September 2009. But our decision on governance for the new common methodology does not prejudge the outcome of this wider governance review. If the ICL review concludes that a different governance model is appropriate then we will seek to change the governance of the common charging methodology through the ICL review at the same time as changes are implemented to other codes.

Rationale for an Ofgem decision on the common methodology

1.16. We are committed to doing all we can to ensure that DNOs can achieve the implementation of the new common charging methodologies ahead of next price control review. We recognise that there is an exacting timetable for implementation that will only be achieved if we are clear about what DNOs are required to implement and if we take a pragmatic approach to dealing with significant implementation issues or unforseen results when the methodology is applied to specific networks.

1.17. There has been a long running and substantial debate on the most appropriate methodology for distribution use of system charges with no agreement across companies, consultants or academics on either EHV or HV/LV charging arrangements. Responses to our July consultation overwhelmingly agreed that we

[3] Code Governance Review: Charging methodology governance options', Ofgem, 132/08, 17 September 2008. See our website at http://www.ofgem.gov.uk/Licensing/IndCodes/CGR/Pages/GCR.aspx.

should make a decision on the common methodology and that it would be very difficult to meet the April 2010 timeline if DNOs had to work together to agree the methodology.

1.18. The detailed decision on the charging methodology set out in this document is the first step in providing DNOs with the clear direction they need in order to implement new charging arrangements. However, it should be noted that the decision represents only the starting point for the methodology and we expect it to improve and evolve post April 2010 through the governance arrangements.

1.19. The decision in this document covers EHV charging and HV/LV charging for both demand and generation customers. Some of the detailed parameters will be worked through as we formulate charging templates in autumn/winter 2008. The decision is not able to cover off fully areas where there is interaction with the ongoing price control review process. In particular, elements of generator charging, including scaling and revenue pots are linked directly to that review. In addition, the treatment of generators who connected prior to April 2005 (and who are currently exempted from paying for use of the distribution system) will be taken forward under the price control review.

1.20. In some areas of the methodology further DNO work is required and this is set out further in Chapter 3 and Appendix 2. We also recognised in July that there are some issues (specifically IDNO charging and HV/LV generator charging) where we have been urging DNOs to take action for some time[4]. We do not wish to halt progress in these areas. We expect DNOs to deliver their final solutions in these important areas as soon as possible to deliver against the relevant charging objectives and therefore envisage a two-tier process.

1.21. In particular, in respect of IDNO charges, DNOs need to take steps to bring forward appropriate common charging arrangements and ensure that they are compliant with the requirements of the Competition Act 1998. Given our concurrent powers under competition law we do not think it would be appropriate for us to determine the methodology for DNOs. We also note that IDNOs have raised issues with all of the methodologies currently in use by DNOs and there is clearly need for further industry debate and discussion before we can make a decision on a common IDNO charging methodology.

1.22. We are, however, committed to assisting the industry reach a solution on IDNO charging as soon as possible. We require DNOs to continue to work with IDNOs to discuss the most appropriate approach to IDNO charging and to bring forward proposals ahead of the implementation of the common methodology. We are willing to continue to facilitate and mediate in the process of defining a common IDNO

[4] See, for example, page 3 to our July 2007 letter on WPD's IDNO charging proposals: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/WPD%20S%20Wales%20IDNO%20DNO%20charging%20mod%20FINAL%20120707.pdf and page 10 of our decision on EDF's LRIC modification proposal: http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/EDF%20(SPN)%20021%20decision%20letter.pdf.

approach. In order to assist this group, we would consider providing 'minded to' decisions on material issues arising should DNOs wish to understand how they are progressing towards a common solution on this matter.

Implementing the methodology

1.23. The detailed description of the charging methodology set out in this document still leaves room for interpretation. If the CLM is successful we will work with the industry to achieve generic charging templates over the autumn/winter of 2008/09. This will take the methodology down to a greater level of detail providing DNOs with the clarity they require before they begin to implement the methodology in their own areas in early 2009. We will ensure that the template is an appropriate reflection of the common methodology, further reducing the risk to DNOs of failing to meet their licence obligations.

1.24. DNOs will populate the templates to enable them to calculate charges for submission to the Authority, along with the common methodology by 1 September 2009. The Authority will then decide whether to approve the common methodology by 31 December 2009.

1.25. As stated in our July document, the methodologies have been untested on some networks and for this reason we do not expect the DNOs to apply the methodology "blind". It is for DNOs, consistent with their legal obligations, to determine whether it is appropriate to apply the output of the methodology where the implementation of the approach set out in Appendix 2 appears to give counterintuitive or inappropriate results.

1.26. Where this is the case, we expect firstly that DNOs will discuss the matter with us so that we can assess whether there is a generic issue which can be addressed by alterations to the methodology and the template ahead of April 2010. In the limited circumstances where changes to the methodology and template do not provide a solution to a specific situation and where the methodology is still producing anomolous and non-cost reflective charges we expect DNOs to propose suitable alternative arrangements. These arrangements should be based on their best assessment of the long run incremental cost of providing capacity at that point on their network. We also expect DNOs to publish a clear explanation of the reasons for any adjustments and why they deliver more cost reflective charges at that location than the use of the LRIC model.

1.27. We will be considering whether it is appropriate to formalise the steps that a DNO must take before putting in place alternative arrangements to those set out in Appendix 2. Consistent with our better regulation duty and to reduce the burden and regulatory risk associated with dealing with these anomolous situations, our preference would be to issue guidance on this matter to set out in advance what a DNO is required to do in these circumstances which DNOs may then wish to incorporate as specific steps in their methodology. We will seek the views of DNOs and users on this matter. If it proves difficult to predict and address the full range of anomolies through upfront guidance or steps in the methodology, we will consider issuing derogations to DNOs from the common charging methodology on a case by case basis.

Dealing with volatility

1.28. We also recognise that the new methodology may cause both a one-off step change in charges for initial implementation and year on year charge volatility. We note the concerns that generators and smaller suppliers in particular have raised in this regard and recognise, for example, that year on year charging volatility can be a deterrant to investment in distributed generation and a barrier to entry to the retail market.

1.29. For these reasons, and as a minimum ahead of April 2010, we will require DNOs to publish their charging models on their websites and publish annually long term tariff scenarios to help customers understand the range of future charges. By April 2011 DNOs will have to develop and bring forward proposals for longer term products that would offer generators and customers the choice of fixing their network charges in return for making a long term commitment to pay them, to help customers manage the risk of charging volatility. We would also expect DNOs to consider developing more sophisticated web based tools to help customers to understand and model their future charges. We will consider in due course whether to formalise this in conditions as part of the approval of the common methodology.

1.30. DNOs should continue to work together post April 2010 to consider how the new common methodology may be modified to reduce the degree of year on year volatility and to improve the transparency and predictability of charges for customers.

1.31. In the same way that we require DNOs to deal proactively with any non-cost reflective charges resulting from the methodology (see above) we would expect DNOs to "sense check" the one-off step changes in tariffs that the methodology may produce. Again, we require DNOs to bring these issues to us and consider what, if any, actions should be taken to manage the transition. If not, we would expect the DNO to come forward with proposed alternative arrangements for that specific part of their network or customer category.

Structure of this document

1.32. In the remainder of this document we set out the detail of our decision regarding a common methodology for DNOs.

1.33. Chapter 2 to this document sets out our decision on each element of the common charging methodology, providing reasons for our decision in light of evidence to date on the pros, cons and impacts of different charging models.

1.34. Chapter 3 identifies areas of the methodology that need to be developed by DNOs (and in some cases other parties). Chapter 4 covers governance arrangements, noting responses to our July consultation, setting out our decision and justifying our position. Finally, Chapter 5 explains the timescales and processes by which DNOs will implement the common methodology, assuming the collective licence modification is made.

1.35. Appendix 1 sets out responses to the July consultation and how we have addressed these views in this decision. Appendix 2 sets out the detailed principles and assumptions that form our final decision on the common methodology. We detail in Appendix 3 the scope of work envisaged for consultants if the CLM is made.

1.36. Appendix 4 sets out the Authority's powers and duties; Appendix 5 provides a glossary of key terms whilst Appendix 6 provides an opportunity to give feedback on the consultation and decision process associated with this project.

1.37. Alongside this document we are publishing statutory consultation documents on our proposals which include full details of changes to the electricity distribution licence.

2. Our decision

Chapter Summary

This chapter sets out our decision on each element of the charging methodology along with the reasons for our decisions.

Principles

2.1. The principles for the structure of charges projects are well rehearsed in various documents published on our website in 2000 and from 2003 to 2008[5]. As well as developing methodologies to better meet the relevant objectives under SLC13, Ofgem and the DNOs have identified a set of high-level principles for the project. These principles are: cost reflectivity, simplicity (at point of use), transparency, predictability and facilitation of competition.

2.2. Following our April 2008 consultation document, recent discussions between DNOs and Ofgem have sought to develop these principles further to highlight that a charging methodology should:

- include all relevant information;
- apply to both demand and generation;
- reflect all significant cost drivers;
- minimise the distortion of price signals where any adjustment or scaling of charges is necessary to ensure recovery of allowed revenue;
- recognise incremental costs and benefits on a forward-looking basis by virtue of users' use of the distribution system;
- ensure that charges for EHV users vary by location and utilise power-flow modelling at the EHV level; and
- be transparent and predictable to allow network users to estimate future charges.

2.3. It is agreed that there is an inevitable tension between some of the objectives and principles for use of system charges, and that the development of a use of system charging methodology is a balancing act between competing principles.

Scope

2.4. Work to date on the project has attempted to identify and develop enduring charging methodologies at all voltage levels (EHV, HV & LV[6]) to better meet the relevant objectives and to address these wider goals.

[5] See http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx along with charging modification proposals at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Pages/DistChrgMods.aspx.
[6] Extra high voltage, high voltage and low voltage.

2.5. Recent work has focused on the introduction of more cost reflective charges for EHV-connected customers, independent distribution network operators (IDNOs) and generators at HV/LV. We have previously noted that some changes to the existing distribution reinforcement model (DRM) may be needed to accommodate generator charging.

2.6. There has been some divergence among DNOs over the application of the DRM since it was introduced in the early 1980s. We also note that the structure of end tariffs differs across DNOs: our April 2007 update letter[7] on the project urged DNOs, amongst other things, to consider charging products and structures.

Common methodology

2.7. Figures 1 and 2 below set out the proposed options for each of the main components of the common charging methodology.

2.8. For the avoidance of doubt, commonality will need to cover the following elements:

- the mathematics used in the calculation of charges at EHV/HV/LV for demand and generation customers;
- revenue reconciliation (or scaling);
- IDNO charging;
- common tariff structures; and
- reactive power charges.

EHV demand & generation

2.9. This section sets out our decision on the EHV demand and generation model of the common charging methodology together with reasons for our decision.

2.10. As set out in our July decision and consultation letter, the options for an EHV level model are an approach proposed by the G3 group of companies, variants of the LRIC approach developed by the University of Bath and DLT Consulting (and considered by WPD, CE and EDF to date) and a hybrid LRIC/ICRP approach that has been developed by ENW. We have summarised the different approaches in Table A1 below.

[7] April 2007 update letter: 'Structure of electricity distribution charges: update on progress and next steps', ref 78/07, available on our website at http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Pages/DistChrgs.aspx.

Figure 1: Summary of the options for a common marginal cost model

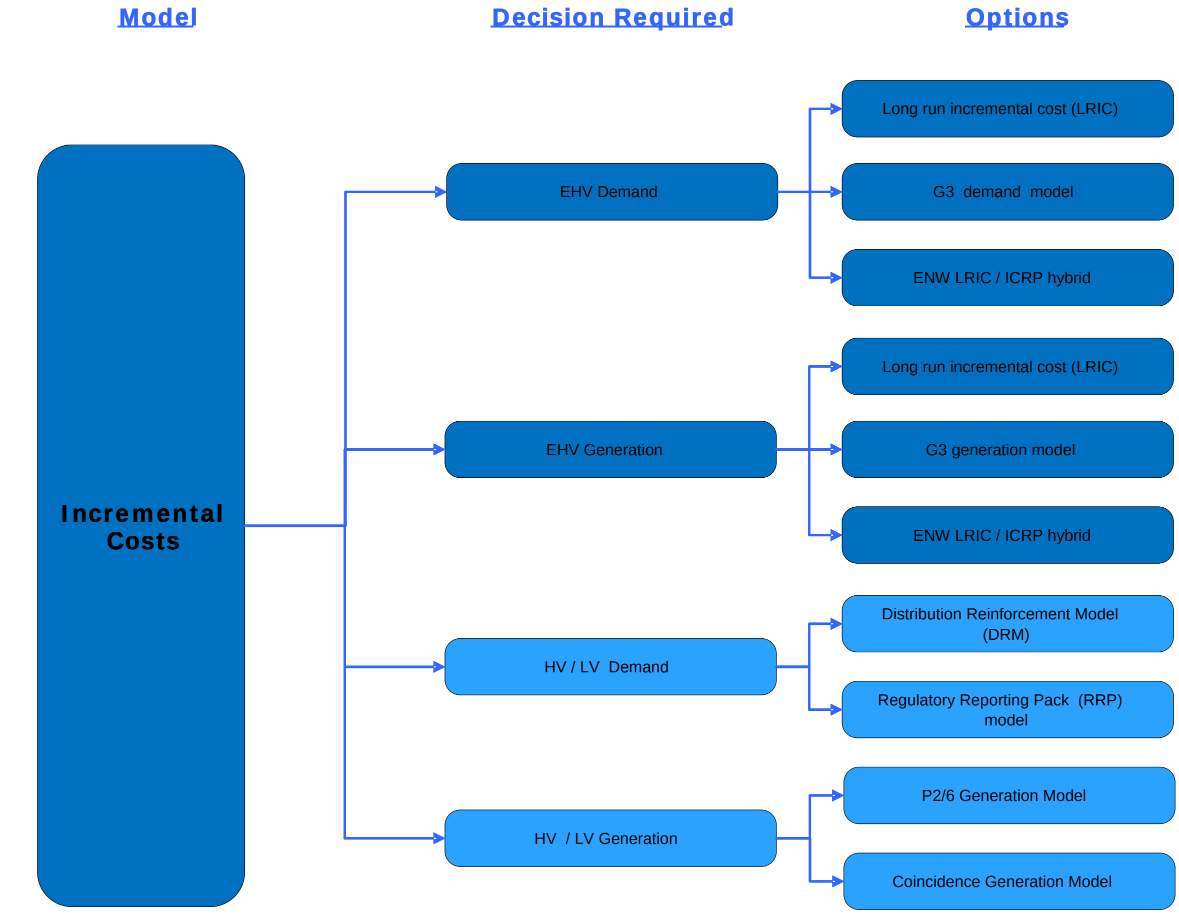


Table A1: EHV models

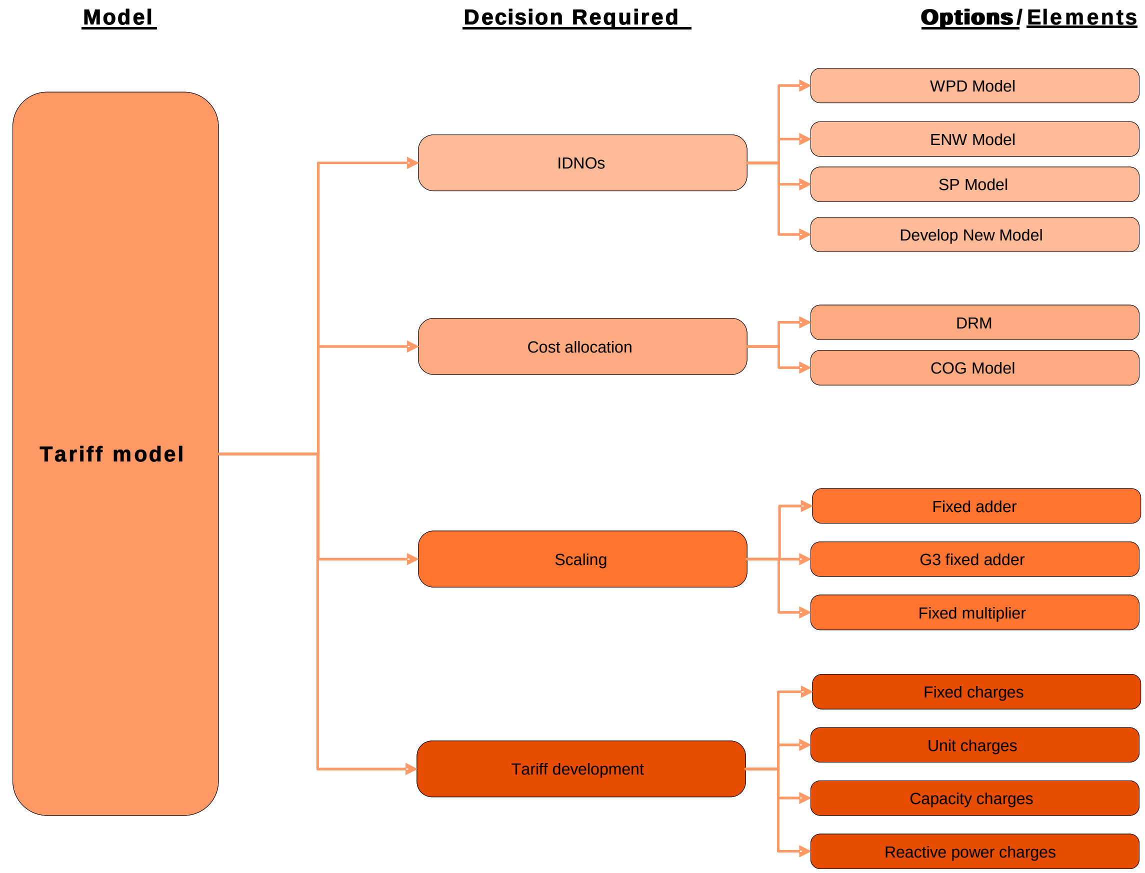
EHV models	SSE, SP and CN G3 approach WPD LRIC approach EDF LRIC approach ENW hybrid LRIC/ICRP approach

2.11. Our decision at EHV is to require DNOs to use a LRIC model that is broadly in line with WPD's current approach applied for both demand and generation at the EHV level. In the subsections below, we set out why we have decided that a LRIC approach for the EHV level network, rather than alternative methodologies that DNOs including G3 have developed, best meets the project goals and objectives. We set out our views on how LRIC meets the key charging principles and what arrangements need to be put in place to mitigate the unintended consequences of this approach.

Project goals and objectives

2.12. On a demand level, all of the proposed models appear to meet the wider project goals by introducing charging structures that, compared with existing methodologies, better meet the objectives of facilitating competition in the generation, distribution and supply of electricity.

Figure 2: Summary of the options for a common tariff model



2.13. Each of the models uses sophisticated load flow analysis to assess and signal how incremental use of system will impact on DNO costs as well as considering how generation may impact on distribution systems in terms of the investment costs that may be deferred as well as imposed on DNOs.

2.14. However, from a high level principles point of view, we consider LRIC represents the best 'foundation' for promoting better and more efficient charging, planning and future investment in distribution networks.

2.15. The LRIC demand model provides a simple method to value spare capacity and to signal the economic cost and benefit from incremental use at different locations on the network. The estimation of forward looking incremental cost on this basis, in principle, links use of system charges to small changes to projected growth in demand and so associates network users' behaviour with the investment costs of the assets they utilise.

2.16. Another key objective in the promotion of more efficient charging has been to drive more efficient behaviour by new and existing customers connecting to EHV networks by providing locational signals to customers. In this context, the load flow analysis and charges in the LRIC demand model have been developed to be applied at a nodal level so as to provide the maximum granularity of locational incremental cost signal for user charges. We consider that charging on this nodal basis provides more cost reflective charges than charging on a network group basis as the G3 approach prescribes. The model also produces a strong economic signal when network assets are more highly utilised to signal to customers impending reinforcement at that location (node).

2.17. The LRIC generation model applies similar principles as on the demand side by assessing the impact of incremental generation on load flows and the forward looking incremental costs incurred by network operators. By doing so, the charges produced by the model, in principle, should also help promote more efficient behaviour by generators and recognise where generators provide a benefit (subject to the P2/6 engineering standards) as well as a cost to network operators. This should influence their decisions on where to locate and connect and lead to more efficient investment in the networks over time.

2.18. The similarity in principles and cost drivers used in the demand and generation side of the LRIC model provides symmetry between the charges for generation and demand. We consider such a symmetric approach is crucial if licensees are to provide cost reflective economic signals to both demand and generation network users who wish to use the same network assets and contribute collectively to system security levels.

2.19. The fundamental differences in the manner in which the G3 model calculates demand and generation does not facilitate this symmetric approach. In the context of use of system charges, we think this is important so as to present consistent cost signals to both forms of network user at particular parts and locations on the EHV network and so that, in principle, all consumers respond to similar locational incentives and charges encourage both the development and competition of DG and demand side management.

2.20. A LRIC approach for demand and generation should, in principle, value and reward efficient use of the distribution network by customers in local parts of DNOs networks as system configuration changes and new or better managed load and generation affect the utilisation of network assets. As a result, we think that of all the charging models that are currently developed and widely understood by the industry, LRIC is the most consistent with the expected changes to distribution networks and with the greater uptake of DG.

2.21. As regards the G3 demand and generation model, and as we noted in coming to our decision for SP's recent proposed modification, we consider aspects of this model to be a significant improvement on DNOs current EHV charging methodology, in particular, the use of power flow analysis and long term development data to produce locational charges for EHV demand.

2.22. However, we also noted our concerns with the generation side of the G3 approach related to issues of simplicity, counterintuitive outputs from the generation model and the degree of averaging[8]. These concerns with the generation side of the G3 approach are a further reason that we believe the LRIC model to be the best available 'foundation' for an EHV charging methodology rather than the G3 approach.

2.23. We consider that LRIC values spare generation capacity in a more appropriate way than the G3 approach. Analysis undertaken on the G3 generation model indicated that due to the mechanics of the model, in some circumstances, incremental charges would increase even if years to reinforcement increased and the cost of that reinforcement decreased[9]. We did not consider that a model which is capable of producing these results is an appropriate methodology to adopt as a common approach across all DNOs.

2.24. In a similar way to the G3 model, our review of the 'IICRP' (LRIC/ICRP hybrid) model developed by ENW suggests there are significant positive features and improvements with this approach relative to DNOs' existing methodologies. However, the need for DNOs to develop two charging methods (both LRIC and ICRP) would be burdensome on DNOs in light of the need to meet the challenging timescales for this project.

2.25. Given the benefits which we consider will be realised from a LRIC based common methodology, we consider that this model is the most suitable basis for establishing a common methodology relative to the other models proposed to us by DNOs.

2.26. We note the significant concerns that have been raised with the LRIC approach and how these may detrimentally impact on wider goals for distribution charging. As discussed more fully in the section on transparency and predictability, DNOs and other industry parties have raised concerns with the potential volatility of the charges produced by LRIC. The model has also been criticised as producing excessive levels of charges under certain system conditions which we discuss further under facilitation of competition. As set out in Chapter 1, we expect DNOs to deal proactively with any non-cost reflective charges resulting from the methodology as well as "sense checking" the one-off step changes in tariffs that the methodology may produce.

2.27. We have considered all of these issues at length. In some cases, we consider that the concerns raised either are acceptable outcomes of the model, or we have

[8] For the detail behind these concerns please see p10-15 of the Authority's decision letter on SP's G3 proposal (PR-08-002) http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgMods/Documents1/SPD%20Decision%20letter.pdf.

[9] See the Authority's decision on SP proposal PR-08-002 at the link above.

addressed them in our approach. We require DNOs to take specific measures to address concerns they have with outputs to the model, as discussed further in Chapter 1. There may be some further issues that can be addressed by DNOs and the industry as part of the governance process once a foundation LRIC based approach has been put into place for 2010. We discuss this issue in more detail below.

Cost reflectivity

2.28. In the context of the GB electricity distribution industry, where DNOs charging methodologies serve the purpose of structuring user charges, we believe the high level principle on which the LRIC model is based – charges that are based on incremental cost – is the appropriate starting point for determining charges.

2.29. We believe LRIC, which is based on incremental cost, is the better foundation for pricing methods with the objective of promoting more efficient network development to meet customer demand. While we cannot determine how consumer demand will respond to price signals, small reductions in growth in highly utlised parts of the network could result in significant savings as set out in Chapter 1. In contrast, the G3 demand and generation methods, which are based on total cost, provide less sharp price signals and as such are less suitable as a common baseline methodology.

2.30. On the generation side, we consider that the smaller granularity of increment used in calculating generation charges under LRIC is more appropriate than the G3 model's use of the 85th percentile of all generation connected at each voltage level. It also means that demand and generation charges are derived from the same starting point.

2.31. Given the goals that the project set out to achieve and the evolving and profound changes that are expected for distribution networks, charges that are based on incremental cost appear the better foundation for signalling to customers the impact their actions may have on DNOs long term capital costs.

2.32. Although investment in network assets and capacity is "lumpy" and typically incurred in a step wise fashion, the scale and the type of investment in distribution networks is also locally determined and to a certain extent suited to a charging model that assesses costs in response to smaller and more discrete changes to projected demand. The model needed to achieve this degree of cost reflectivity has also been demonstrated to us (in considering DNOs' work to date) to be relatively practicable to implement using available load flow analysis and software.

2.33. We note the concerns with LRIC methods that were raised by respondents suggesting that LRIC does not take account of all relevant reinforcement costs drivers. In particular, that they ignore fault level costs unlike the model proposed by G3.

2.34. We note that fault level costs are predominantly driven by one off connections rather than from ongoing system use. In addition, RRP cost reporting data and DNO forecasts suggest that fault levels are currently not as significant a cost driver for most EHV networks relative to other cost drivers such as thermal capacity requirements. We therefore consider that, at this time, fault level driven costs incurred by DNOs continue to be best recovered through connection charges.

2.35. This is an area we would expect DNOs to keep under review and the proposed new governance arrangements would allow the methodology to evolve to address the issue of fault levels if it becomes clear this is a significant DNO cost driver.

2.36. We also believe LRIC to be more cost reflective as the model has been developed to be applied at a nodal rather than a network group level as prescribed in the G3 model. We believe this provides a granularity of cost reflectivity that maximises the benefits from load flow analysis and the locational incentives shown to customers.

2.37. We do recognise that the benefits and the cost reflectivity of a nodal model are dependent upon the load flow conditions and the contingency analysis that is used by a DNO to derive forward looking costs. It is also possible that the use of nodes in a charging model will increase the complexity and the unpredictability of customer charges. We believe that it is possible to mitigate these concerns through further development of information to customers to enable them to predict their charges. In addition, the further consideration by DNOs of long term charging products and ways to address volatility, should this occur, are discussed in Chapter 3.

2.38. We would emphasise that our decision to require LRIC is to establish a foundation for a longer term common method for the industry. As discussed previously in Chapter 1, we will require the DNOs to take specific measures to address concerns with the predictability of the model as part of the common governance process post-2010 with initial measures in place for 2010.

Simplicity (at point of use), transparency & predictability

2.39. The LRIC model takes a ‘bottom-up’ approach for establishing cost estimates and assumptions for the EHV level network. Other models including those produced by G3 and ENW have taken a similar bottom-up approach.

2.40. Relative to DNOs' existing approaches, we accept that all the proposed methods for the EHV level, including LRIC, require an increase in the level of complexity and technical knowledge. This is largely the result of the use of load flow analysis to estimate costs at network nodes and the reliance of all of the models on engineering assumptions and pre-determined reinforcement schemes.

2.41. The use of a bottom-up approach to derive estimates of forward-looking cost is therefore a key trade-off as regards the simplicity and the cost reflectivity of DNOs charging methodology for EHV level networks.

2.42. However, given the high level goals for the structure of charges project, and the limitation of LRIC to the EHV level network, we believe this is an appropriate trade off to promote more efficient use of distribution networks by customers.

2.43. DNOs have demonstrated that provided inputs and assumptions are clear and/or based on publicly available sources, a simple bottom-up approach can be used to estimate incremental cost and can be computed with limited technical expertise while being able to estimate costs within an acceptable modelling error margin.

2.44. The transparency and the predictability of the EHV charges are critical to providing network users with an understanding of what drives their network charges. Transparency and predictability are particularly important if demand and generation are to be expected to respond to the granular locational incentives produced by more cost reflective charging models.

2.45. Responses to our July decision letter and previous project consultations suggest that transparency is achieved by DNOs being clear about how system reinforcement methods are selected as well as their charging models making extensive use of clear modelling and cost assumptions. Where practicable, the use of data from publicly available sources such as the long term development statement is also considered to improve the transparency of use of system charges.

2.46. The LRIC model, similar to the G3 and ENW approaches, should be able to produce more transparent charges for customers relative to DNOs current methods provided that locational charges are published in order that customers can better understand the implications of their use of the distribution system. Similar to other proposed methods, the LRIC model makes extensive use of the long term development statement to outline the system's configuration as well as for load flow assumptions. We believe this will help improve significantly the transparency of consumers' charges.

2.47. Predictability is a key concern for users where charging models are cost reflective but subject to annual changes in the assumptions and network configuration which may drive volatility in charges. Respondents to our July decision letter and previous consultations, raised concerns that the LRIC model, relative to alternative approaches such as the G3 model, may lead to greater instability of charges because of the nodal level of the analysis, the responsiveness of the marginal cost estimate to the main modelling assumptions (e.g. growth and utilisation) and by the fact cost estimates are based on load flow analysis.

2.48. We agree that predictability is a key objective for distribution charges in order for a common methodology to achieve the wider goals for the structure of charges project. However, we consider it is appropriate to put in place a foundation methodology which is cost reflective which can then be improved and developed to be more stable and predictable as part of the common governance process.

2.49. As discussed below, our decision includes the conclusion to hold key variables such as the growth rate and size of increment constant. This should help to improve the stability and to a certain extent the predictability of EHV charges.

2.50. We also expect DNOs to introduce a range of measures as set out in Chapter 1 to allow customers to estimate the impact on their charges from changes to key variables.

2.51. In general, we expect DNOs to take steps to improve the predictability and transparency of LRIC as part of the common governance process post-2010 with initial steps being taken as part of implementing the model as the common baseline in 2010.

Facilitation of competition

2.52. A key driver for the structure of charges project has been to develop more cost reflective charging structures for both demand and generation customers. The aim is to encourage both types of customer to make more efficient use of the EHV level distribution network.

2.53. As we set out above, we believe the LRIC model, provides the most effective foundation for an enduring EHV charging model with these goals.

2.54. For similar reasons, we think that LRIC is the model that is most likely to effectively promote competition in electricity markets by producing cost reflective charges which encourage demand side management by larger EHV demand users and the uptake of DG technologies in Great Britain (GB).

2.55. A number of responses to our July decision letter raised concerns with the level of charges produced by the LRIC model under certain system conditions and how this may detrimentally impact on competition. These concerns included:

- that the model produces excessive charges under conditions of high utilisation and low growth rates; and
- that there are potential risks for competition law breaches with the LRIC approach which calculates an incremental charge and then applies this charge to total rather than incremental demand.

2.56. As regards the first concern, our decision includes the conclusion to hold the growth rate used in the common methodology at a constant rate of one percent for all GB EHV networks. Although a one percent growth rate still provides a strong economic signal to customers where assets are highly utilised, we believe the use of this constant growth rate mitigates some of the extremes that have been raised with the model, in particular, the production of excessive annual charges under conditions of high utilisation and low (less than 1%) growth rates.

2.57. Although load growth is expected to vary across DNO networks, we have selected a 1% growth rate as we believe this provides a reasonable long term approximation of load growth on EHV networks across GB and is appropriate given it is applied in a modelling context of a long run charging model.

2.58. Government figures indicate that in the last 25 years, the growth in electricity demand has been between 1% and 2%[10]. We have chosen the figure of 1% as it represents the lower end of this consistent trend and thus allows for slightly lower demand growth in to the future than has been seen historically. Given all the evidence available we consider this represents the most sensible global assumption to make.

2.59. As regards the second concern, we would emphasise that if, when DNOs come to apply the model, it is considered to produce 'excessive' charges that are considered to be in breach of competition law, we believe it would be necessary for the DNOs to consider the drivers and the impacts of these charges for customers rather than applying the methodology "blind".

2.60. If the high levels of charges are driven by very highly utilised system conditions or from delayed or avoided reinforcements, then it may be necessary for a DNO to consider whether it is both fair and/or appropriate to provide this charging signal to consumers given the modelling basis for how charges are determined. In this case we expect the DNOs to take the approach to deviations from the methodology set out in Chapter 1. That is, to be proactive in bringing issues to Ofgem and proposing solutions consistent with DNOs' broad statutory obligations.

2.61. We would also highlight that revenue reconciliation and employing an annuity in deriving LRIC charges may reduce the scope for excessive charges.

2.62. As regards revenue reconciliation, the requirement for a £/kVA fixed adder to be used for scaling purposes in the common methodology, we believe will have a significant impact on the absolute and relative level of customers' charges. The LRIC element of a customer's final charge is a function of their kVA demand, the global growth rate, and the utilisation and reinforcement cost of the assets the customer utilises. The scaling element of customer's charge is a function of price control allowed revenue and their kVA demand.

2.63. Relative to other customers, we cannot predict how an individual customer's charge will relate to the total reinforcement cost of the assets that customer utilises except to highlight that scaling will ensure that customers' relative charges in total do not exceed DNO allowed revenue.

2.64. In terms of the annuity factor, we note the LRIC method uses an annuity factor over the life time of the asset (40 years) to derive a annual £/kVA charge. As

[10] This figure comes from a BERR 'Energy trends' document which can be found at: www.berr.gov.uk/files/files11864.pdf.

discussed below, this would seem an appropriate and justified method to spread the derived cost in customers' annual charges given the incremental cost should be applied to incremental demand. As a result, the annuity factor provides some justification for the level of a customer's LRIC price in a given year.

2.65. For these reasons, as well as the degree of discretion given to DNOs regarding the final charge they can provide to their customers, we are not persuaded that an LRIC method will necessarily conflict with competition law.

2.66. Furthermore, as set out in Chapter 1, if, when DNOs come to apply LRIC as the common methodology, it produces charges that do not appear cost reflective based on the DNO's assessment of their actual investment plans for that part of the network, we would encourage DNOs to bring forward any issues and/or solutions in respect of these for the Authority to consider.

2.67. The methodology provides some discretion to make appropriate adjustments to the outputs of LRIC where it appears to a DNO that charges do not reflect their assessment of the costs they would actually incur at a network location under load growth: as such, a DNO would not be immune from a challenge under competition law. However, if the DNO believes that the inputs and the methodology are leading to perverse results we would encourage them to notify us so that we can consider whether the methodology needs to be changed on a case by case basis.

Other issues

2.68. We also note a number of respondents' additional concerns with LRIC methods, in particular:

- the application of the annuity factor over the life time of the asset; and
- the incompatibility of the model with the current 'shallowish' connection charging boundary.

2.69. As regards the application of the annuity factor, we are not persuaded that it is inappropriate to apply an annuity factor over the life time of the asset (40 years). As mentioned above, LRIC charges are based on incremental cost and should be applied to incremental demand. As a result, an annuity factor would seem a practical method to spread the lumpy capital costs across incremental demand once the charge is applied on a £/kVA basis to asset demand.

2.70. Furthermore, given consumers are expected to pay the incremental cost from a small change to demand for assets that are likely to be used by many other consumers - both over the lifetime and reinforcement cycle of an asset - an annuity applied over the average economic life time of the asset would seem an appropriate and justified method to spread the incremental cost in customers charges given these assets will be used over their capital life time.

2.71. As regards the incompatibility of LRIC with the current 'shallowish' connection boundary, we do not agree that the model will result in incorrect economic signals being provided to demand and generation. A cost reflective use of system charge that is reflective of local network reinforcement costs from load growth and existing user demand also requires a shallow connection charge to reflect the cost of any local connection works to the network.

2.72. The shallowish connection charge and locational incentive provided by LRIC will both provide a locational message to network users and it is for the individual consumer to consider the incremental costs (and benefits) in total from locating on a particular part of the EHV network. We note concerns over possible 'pancaking' of charges and raise this as an issue for future development in Chapter 3.

HV/LV demand

2.73. Our July consultation document presented two options for a HV / LV demand charging model. We have summarised the different approaches in Table A2 below.

Table A2: HV/LV demand models

HV/LV demand model	DRM Cost allocation using RRP[11]

2.74. Our decision is to require DNOs to use a form of the DRM model for HV/LV demand. For the methodology to be common going forward we specify in Appendix 2 a specific DRM approach as DNOs' methods have diverged since the DRM was implemented in the 1980s. The key reasons for our decision are set out in the subsections below.

Cost reflectivity

2.75. Similar to the EHV level charging model, we believe that establishing a cost reflective foundation for the HV/LV demand model that can then be improved and developed over time is the appropriate approach for selecting a common methodology.

2.76. In this respect, although the RRP model has been argued to have desirable characteristics in terms of being predictable and simple for customers to understand, we consider it to be less cost reflective than the DRM model currently used by DNOs. As a result, we believe it is a less appropriate model for a common methodology baseline.

[11] Regulatory reporting pack, disaggregated price control-related information provided to Ofgem annually.

2.77. As set out in our recent decision letter for the SP modification proposal[12], we believe the RRP model to be a backward looking total cost model that produces charges which reflect historic total expenditure whereas the DRM considers a forward looking increment.

2.78. The DRM is a well understood, simple and practical method to calculate forward looking cost for lower voltage level charges. As the model produces charges based on providing additional capacity, we consider that it is capable of sending better economic signals to customers by illustrating what the impact of their behaviour is on the network.

2.79. In addition, because the RRP model is based on total historic data, it risks 'losing-touch' with future incremental distribution costs, and relying on a historic approach may also reflect costs delayed for operational or business reasons.

2.80. For these reasons, we believe the DRM most effectively meets the objective of providing a cost reflective foundation for calculating demand charges for HV/LV networks.

Simplicity (at point of use), transparency & predictability

2.81. Similar to EHV level models, the simplicity, transparency and the predictability of HV/LV charges are critical to providing networks users with an understanding of what drives their network charges.

2.82. Both of the proposed HV/LV demand models are relatively simple models relative to the proposals for the EHV network. This is because of the lumpy nature and complexity of lower voltage level networks. They are easy to understand and to implement provided modelling assumptions are made clear to network users.

2.83. The RRP model is potentially easier than the DRM approach for customers to understand as costs are sourced from the regulatory reporting pack and as such are driven by historically incurred costs averaged over a number of years.

2.84. In contrast, the mechanics of the DRM may not be well understood by industry stakeholders. We accept that the DRM model is currently not transparent to users as charges are based on the cost of building a hypothetical network designed as an extension to the existing network and this analysis is not made publicly available to network users.

[12] Decision in relation to SP's proposal to modify its electricity distribution use of system charging model at EHV, HV and LV, September 2008: http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=501&refer=Networks/ElecDist/Policy/DistChrgMods.

2.85. However, as set out above, we believe the DRM is a more cost reflective foundation for calculating demand charges for HV/LV networks. Provided assumptions can be made clear and modelling analysis used to determine charges is provided to consumers, we believe the DRM requires less of a trade-off with cost reflectivity of charges relative to the RRP model.

2.86. Furthermore, while the use of rolling average RRP data does give an element or predictability in the RRP model, we would stress that as RRP data is not publicly available to users, it is not more transparent than the DRM approach at present. While the DRM has produced relatively predictable charges for the last 20 years our analysis of RRP data to date suggests some DNOs experience relatively large year on year variations in reinforcement costs at each voltage level. This would lead to volatility in charges under G3's RRP approach.

2.87. As with EHV level models, improving the predictability and transparency of the DRM is an area we would expect DNOs to develop with the industry as part of the governance process once the model has been put into place from 2010. We would expect DNOs to make the DRM templates publicly available to customers to improve the transparency and understanding of the cost drivers for lower voltage level networks.

Facilitation of competition

2.88. We consider that the DRM will have a greater beneficial impact on competition relative to the RRP model. This is based on the greater cost reflectivity of the model and the potential for development of the transparency and predictability of modelling inputs with industry once a baseline method has been implemented.

HV/LV generation

2.89. Our July consultation document presented two options for an HV / LV generation charging model. We have summarised the different approaches in Table A3 below.

Table A3: HV/LV generation models

HV/LV generation model	P2/6 G3 RRP approach WPD (DRM coincidence) approach EDF (DRM coincidence) approach ENW (DRM coincidence) approach

2.90. Our decision is to require DNOs to use a DRM approach combined with P2/6 factors for HV/LV generation. The key reasons for our decision are set out in subsections below.

Cost reflectivity

2.91. We note that all models take a broad-brush assumption that DG can give rise to long run negative costs where they are expected to reduce upstream network costs. All of the models assume that currently, HV/LV generator networks are demand dominated and so generators will impose a net benefit on DNO networks by diverting upstream power flows and contributing to system security.

2.92. Each of the models takes a different approach to reflect these costs (benefits) and bear some relation to the P2/6 statement.

2.93. The P2/6 approach proposed by the G3 applies the P2/6 statement more rigidly in order to provide more transparency and predictability to network users. Generator deference of demand-triggered reinforcement is related to the probability of the generation commencing output, represented by an F (probability) Factor.

2.94. The approaches proposed by EDF, ENW and WPD use a similar method but instead apply a coincidence factor within the DRM (based on a generator's load factor) to determine the level of credit attributed to generation on HV/LV networks. As a result, generator deference of demand-triggered reinforcement is related to a generators load factor as a proxy for its coincidence factor with system peak.

2.95. We consider that at present, the more ridged application of the P2/6 statement in the G3 approach is the better foundation for a common HV/LV generator charging methodology.

2.96. This approach takes account of different types of generation and as such is more flexible to future developments in the industry as the P2/6 security guidelines are updated. It also aligns generator charges more closely with the security standards that DNOs build the networks to and so, in principal, will provide the correct incentives to promote DG connecting to HV/LV networks.

2.97. In general, we believe the P2/6 approach to be a suitable baseline for determining granular generator charges that recognise the benefits from DG connected to HV/LV levels in the context of a GB common charging methodology.

Simplicity (at point of use), transparency and predictability

2.98. All of the proposed models take a more general approach at the HV/LV level given the complexity of the network. We agree that at present, the charging methodology at this level is more suited to a pragmatic approach being undertaken rather than a model that provides strong locational signals to generators.

2.99. As a result, it is our view that the P2/6 approach – which makes use of F-Factors outlined in a public document – would appear the most simple and understandable for stakeholders given these were determined by industry based on agreed principles.

2.100. There is a clear trade-off between more accurately reflecting a generator's contribution to system security and assessing this on a transparent, predictable and consistent basis. All four of the proposed approaches have been designed to be transparent and predictable for users given the need for simplicity for HV/LV network charges at present.

2.101. The P2/6 approach is significantly strong in this area because of its use of the publicly available P2/6 statement to value a generator's system security factor in a consistent framework.

Facilitation of competition

2.102. We consider that the P2/6 approach of using F-Factors will have a greater beneficial impact on competition.

2.103. This is based on the greater transparency and simplicity the approach provides for generators. In the context of a common charging methodology, the use of coincidence factors could introduce inconsistencies across DSAs which may increase complexity and potentially distort competition.

2.104. The P2/6 approach is also less subject to the accusation that establishing a broad network 'hurdle rate' for a generator load factor will discriminate against different forms of generation.

Revenue adjustment

2.105. Our July consultation document presented three options for a revenue adjustment mechanism. We have summarised the different approaches in Table A4 below.

Table A4: Revenue adjustment mechanisms

Cost allocation / Revenue adjustment	Fixed adder approach Multiplier for DRM G3 cost allocation plus fixed adder

2.106. As set out in Appendix 2, our decision is to require DNOs to use a fixed adder approach for revenue adjustment with a very small subset of costs being allocated outside the fixed adder.

2.107. All DNOs require some form of revenue reconciliation, or scaling, in order to match the revenue recovered from their charging model to their allowed revenue under the price control.

2.108. The mechanism that is used by a DNO is also important because in practice, a large proportion of its revenue may be recovered through such a scaling mechanism and, as such, may have a significant impact on the absolute and relative level of customers' charges.

2.109. Given all three approaches will allow a DNO to recover its allowed revenue, the key reason for our decision is based on our belief that a fixed adder - by maintaining the absolute relativity between tariffs - minimises any distorting effect on customers' charges, caused by the mark-up over incremental cost.

2.110. We also believe that the fixed adder approach is the most fair, simple and transparent method for customers to understand. In contrast, a fixed multiplier approach, although currently in use by some DNOs, only maintains the proportional relativity between tariffs and as such may distort the cost signals that customers would see. As regards the G3 fixed adder approach, as set out in our decision letter for SP's recent modification proposal, our concern with this method is that the price differential between the different adders at each voltage level may become the predominant economic signal a customer receives.

2.111. Thus the cost signal which demand customers would see is not the part of the network which has the most capacity and least costs, but instead which voltage level has the least scaling. We believe that this may produce perverse incentives to customers to connect at different voltage levels rather than to connect where the costs they incur are the least. We are not persuaded that this promotes economic behaviour in use of system.

2.112. In addition, our decision letter on SP's G3 modification proposal set out that their approach to cost allocation did not appear appropriate, for example in terms of allocating asset replacement costs. Cost allocation is an area we expect DNOs to consider further post 2010. However, for the purposes of the baseline common methodology from 2010 we consider that incremental reinforcement costs should be reconciled to allowed revenue on the basis of a simple fixed adder. As set out in Appendix 2 there is a small subset of costs that can be allocated separately as carried out by various DNOs currently as combined with their DRM approach.

IDNO charging

2.113. Our July consultation document presented four options for IDNO charging. We have summarised the different approaches in Table A5 below.

Table A5: IDNO charging

IDNO charging	No IDNO-specific tariffs (e.g. EDF) IDNO-specific tariffs: WPD IDNO-specific tariffs: SP IDNO-specific tariffs: ENW

2.114. As set out in Chapter 1, DNOs need to take steps to bring forward appropriate common charging arrangements and ensure that they are compliant with the requirements of the Competition Act 1998. Given our concurrent powers under competition law we do not think it would be appropriate for us to determine the methodology for DNOs. We also note that IDNOs have raised issues with all of the methodologies currently in use by DNOs and there is clearly need for further industry debate and discussion before we can make a decision on a common IDNO charging methodology.

2.115. We encourage DNOs to develop a common methodology for IDNO charging as soon as possible; we discuss this further in Chapter 3. We require DNOs to work with IDNOs on this area of work. As set out above we see a role for Ofgem facilitating and, where appropriate, mediating in this process.

Reactive power charging

2.116. Our July consultation document presented three options for reactive power charging. We have summarised the different approaches in Table A6 below.

Table A6: Reactive power charging

Reactive power charging	No reactive power charges (SSE, CE) Reactive power charging: CN and ENW Reactive power charging: other approaches

2.117. Our decision is to require DNOs to use the approach developed by CN and ENW in respect of half hourly (HH) charges. Further details are provided in Appendix 2. For the avoidance of doubt, should charges be levied exclusively on a £/kVA basis[13] then there is no requirement for a reactive power charge. Our decision is based on our belief that this approach is the best method that has been developed to date.

Tariff structures / detail

2.118. We discuss tariff structures in more detail in Chapter 3 as an area for development by DNOs pre-2010.

[13] This, for example, is the case at EHV under WPD's current approach and this was also proposed by SP at EHV in its recent G3 modification proposal.

3. Areas for further development

Chapter Summary
This chapter sets out areas for further development both pre and post 2010. The chapter should be read in conjunction with the detail provided in Appendix 2, where we specify additional areas for further development.

3.1. This chapter reviews each of the areas of the common methodology we believe will require further development by DNOs pre and post-April 2010. This chapter should be read in conjunction with the more detailed areas specified within Appendix 2 as requiring further development.

3.2. We set out here the core elements of each of the areas we expect DNOs to develop, rather than specifying in detail what the methodology should be. The reasons for specifying areas for further development in a number of key areas of the common methodology is provided in Chapter 2.

Elements for further development pre-April 2010

3.3. The main elements of the common methodology that we expect DNOs to develop and address pre-April 2010 are:

- IDNO tariffs;
- tariff structures;
- information to help users predict their year on year charges; and
- implementation issues.

IDNO tariffs

3.4. We encourage DNOs to develop and bring forward to us a common methodology for IDNO charging as soon as is possible. We are facilitating some collaborative work between DNOs and IDNOs currently and we look forward to these proposals being brought forward.

3.5. In terms of key areas for development, we would expect DNOs to bring forward proposals that address:

- the tariff profiles that are assigned to IDNOs;
- the transparency, consistency and predictability of IDNO tariffs;
- the capacity charge, if any, that is levied on IDNOs;
- the avoided costs that may be incurred by a DNO from a IDNO connection; and
- how common fixed costs will be recovered in DNO charges.

3.6. As set out in Chapter 1, DNOs need to take steps to bring forward appropriate common charging arrangements and ensure that they are compliant with the requirements of the Competition Act 1998. Given our concurrent powers under competition law we do not think it would be appropriate for us to determine the methodology for DNOs. We also note that IDNOs have raised issues with all of the methodologies currently in use by DNOs and there is clearly need for further industry debate and discussion before we can make a decision on a common IDNO charging methodology.

Tariff structures

3.7. In terms of tariff structures more generally, our decision is for common tariff structures from 2010. As such, we expect DNOs to develop proposals for common tariff structures including time of use tariffs.

3.8. We recognise that this is challenging given the lead times that DNOs and other parties (e.g. suppliers) may require to develop and implement such proposals – in particular to revise their billing and settlement systems. In view of this we expect DNOs to progress this as soon as possible and to raise promptly with us any concerns over meeting the 2010 deadline. We will consider any such issues on a case by case basis, including whether to derogate from the 2010 deadline. We recognise that further work on common tariff structures may need to be brought forward through a common methodology governance regime post-April 2010.

Information to help customers predict their charges

3.9. DNOs are required to develop proposals pre-2010 to help users predict their charges year on year. Specifically, we consider DNOs should develop 5 year tariff scenarios to enable customers to better understand the potential range of their charges in to the future. We also consider that DNOs should publish charging models to the extent possible.

3.10. There may be more that DNOs can do to provide useful information to customers either in the short or longer term. We would expect further development post 2010 to enable a more sophisticated solution to be implemented as soon as possible thereafter.

Implementation issues

3.11. We expect DNOs to consider and resolve implementation issues as and when they arise and to bring these to our attention on either a bilateral or collective basis. In Chapter 1 and Appendix 2 we have also noted some interactions with the price control review, for example around generator charging.

Elements for further development post-April 2010

3.12. The main elements that we believe will require development post-April 2010 include:

- proposals to improve the year on year stability, transparency and predictability of charges and DNOs' charging models;
- considerations over the 'pancaking' of charges.

Proposals to improve year on year stability, transparency and predictability of charges

3.13. As set out in Chapter 1, DNOs are required to develop longer term charging products in order to address any concerns consumers may have with annual volatility of distribution charges, particularly at EHV level.

3.14. In addition, and as set out above, we require DNOs to develop tool(s) to help customers understand and model their future charges.

Considerations over the 'pancaking' of charges

3.15. SSE's response to our July consultation noted potential pancaking of charges in relation to the LRIC model. This refers to the balance of connection and use of system charges. We consider this to be an issue with any charging model and this is an area for further consideration and possible future development by DNOs and the industry post 2010.

4. Governance arrangements

Chapter Summary
In this we consider governance arrangements, setting out the background, responses to our July consultation, interactions with licence drafting and how the proposed arrangements will be implemented.

Introduction

4.1. Charging methodology governance arrangements provide for the modification of network charging methodologies over time. As such, they provide an essential change control procedure which allows methodologies to be modified in response to changing network conditions. All charging methodologies require governance arrangements. Following our July consultation, this section sets out our decision on the provision for governance arrangements it would be appropriate to introduce for the common methodology as part of the CLM.

Background and options

4.2. In our July consultation we set out our view that, having decided that a licence obligation to deliver a common charging methodology should be placed on all 14 DNOs, it would be necessary to make provision for governance of the common methodology. We set out three high level options for delivering governance arrangements for the common methodology. These were as follows:

Option 1 – Industry code governance

4.3. In this option, we outlined that the common methodology would be subject to the DCUSA governance arrangements. This would mean that suppliers as well as network operators would be able to raise modification proposals to the methodology. We considered that the benefits of this approach would be that it would provide users with greater ability to contribute to the development of the methodology by way of a formal modification mechanism, and that it would take account of an existing industry framework with an already established appeals mechanism.

Option 2: Modify the current DNO licence

4.4. Under this option we set out that we would seek to modify SLC13 to include within the condition that any modification proposal should apply to the common charging methodology, unless otherwise directed by the Authority. To ensure greater industry access to the charging methodology, under this option we set out that we would also propose that the modified condition would set out formal obligations on licensees to consider and formally respond to change proposals submitted by non-DNO industry parties, including holding industry forums, carrying out Impact

Assessments and bringing forward charging methodology modification proposals where appropriate.

Option 3: New Charging Methodology Code

4.5. We set out that the governance arrangements envisaged under this option would be delivered via a standard set of modification rules. We considered a potential benefit of this option would be that in developing a new code, the governance arrangements could be tailored to precisely meet the requirements of a common charging methodology. Conversely, we acknowledge that the potential downside of this option would be that development and introduction of a new code would have significant cost implications for industry parties and this could be viewed as economically inefficient for the number of modifications reasonably expected to be proposed to the common charging methodology.

Responses

4.6. Respondents to the July consultation on governance agreed, that if a common methodology is to be implemented by April 2010, it is essential that governance arrangements are implemented in parallel. There was no clear consensus as to whether the governance arrangements would be best set out in code, or via a licence condition, but there was majority support for Ofgem's view that, regardless of which option is selected, it is important that the modification procedure of the common methodology allows for non-DNOs to have modification proposals considered and consulted on. A majority of respondents considered that creating a new industry code to handle modification proposals would be disproportionate and unnecessarily costly option.

Ofgem's decision

4.7. Our view remains that it is necessary to develop a compatible set of governance arrangements for implementation in parallel with the common use of system charging methodology on 1 April 2010. In reaching this decision we have been mindful of the wider review of charging methodology governance being undertaken by Ofgem's Industry Codes and Licensing (ICL) directorate.

4.8. In their September consultation[14] the ICL team have set out a number of options regarding the possible location and jurisdiction of charging methodology governance, including whether governance should reside in a network code. We do not propose to prejudge the outcome of their review in reaching our decision. Our intention is to put in place a minimum set of governance obligations which are compatible with the wider aspirations of the ICL project, and which are wide enough to be viewed as broadly compatible with any of the main options they consult on, except the maintenance of the status quo. At this stage we do not consider that it is

[14] 'Code Governance Review: Charging methodology governance options', Ofgem, 132/08, 17 September 2008.

necessary or appropriate for us to select from the options outlined in our July consultation in order to deliver the objectives of implementing governance arrangements for the common methodology.

4.9. Our decision is that a licence condition should be introduced under the CLM which obligates DNOs to develop and bring forward, in consultation with other Authorised Electricity Operators (IDNOs, suppliers and generators), a set of governance arrangements for approval by the Authority on or before 1 September 2009. In addition we have decided that it would be appropriate to introduce a licence obligation on DNOs to develop arrangements which have the following core features:

- arrangements must provide for DNOs to organise regular meetings with other Authorised Electricity Operators, and any other interested electricity user, for the purpose of discussing the further development of the methodology;
- arrangements must provide for a process by which DNOs can formally receive modification proposals from other Authorised Electricity Operators, or any other persons whose interests are materially affected, and consult with industry on the merits of those proposals; and
- arrangements must provide for DNOs to have a report prepared for submission to the Authority which sets out the conclusions reached about the modification proposal in question, evaluates the proposal against the relevant charging methodology licence objectives, and makes a recommendation to the Authority concerning the implementation of that proposal.

4.10. We note, that although our decision to introduce a licence obligation on DNOs to develop governance arrangements does not reference a network code, it would not specifically exclude it if the DNOs considered in consultation with industry that it was an appropriate option to pursue.

4.11. We have reached our decision on governance arrangements for the following reasons:

- as set out in Chapter 2 of this decision, there are issues with all of the proposed charging models and it is likely that whatever model was chosen it would need to evolve over time as the market and technologies change and it may be necessary to make changes in the light of practical experience of using it. Given the history of DNO involvement in developing their existing methodologies it is essential that governance arrangements are introduced which allow for incremental improvements to be proposed to the common methodology from its implementation;
- the annual efficiency and risk premium benefits of a common methodology identified by electricity suppliers are dependent on commonality being preserved on an enduring basis. The existing charging methodology governance procedures allow for modifications to be proposed on a DNO specific basis only. The existing arrangements are therefore incompatible with ensuring the methodology remains common over time;
- electricity charging methodologies impact on a wide range of electricity users. In our view it is appropriate that all users have the ability to contribute to the future development of the methodology which affects them. Wider access to charging methodologies by non-DNO users was supported by a majority of respondents to

our July consultation. The existing arrangements do not provide for non-DNO modification proposals to be considered for implementation. We therefore consider it is appropriate to obligate DNOs to create governance arrangements which allow for this to happen; and

- IDNOs consider that existing DNO charging methodologies impact on their revenue margins in an inconsistent and in some cases uneconomic manner and, that existing charging methodology governance arrangements do not create sufficient incentive on DNOs to adequately address these issues. Steps are being taken to address IDNO concerns ahead of the implementation of the common methodology, but the right to raise modification proposals will ensure that IDNO concerns with the common methodology are addressed in a timely manner.

Implementing the governance arrangements

4.12. Through the introduction of Standard Licence Condition (SLC) 50.22, the DNOs will be required to develop, consult on and submit to the Authority for approval, a set of governance arrangements which meet the requirements set out in conditions 50.23 to 50.27. SLC50.22 sets out that DNOs must develop the arrangements in consultation with other Authorised Electricity Operators. In discharging this requirement we would expect the DNOs to engage with IDNOs, suppliers and generators, providing them an opportunity to input and provide feedback on the development of their proposed governance arrangements.

4.13. Where the Authority is satisfied that the governance arrangements submitted under paragraph 50.22 of the new licence comply with the features set out in paragraphs 50.23 to 50.27 it may approve the modification arrangements.

5. Timescales and processes

Chapter Summary
In this chapter we set out the workstreams and timeline for delivering the project.

5.1. We are committed to working with the industry to ensure the timely delivery of this project. Timelines for this project are set out below. They are tight and it will be important to use consultants to help deliver the project. A well resourced central project team comprised of staff from Ofgem and the DNOs may also help project delivery. We will explore with DNOs whether they are able to second people into such a central team, if the 1 October 2008 collective licence modification proposal (CLM) is successful. Work required to deliver the project falls into 3 key categories:

- developing governance arrangements;
- addressing the areas in the methodology that require further development; and
- implementing the methodology.

5.2. Below we set out each of these workstreams, explaining the role of different parties, the process by which work will be conducted and the output of each workstream. The table at the end of this Chapter provides a timeline for delivery of a common charging methodology by the DNOs and formal governance arrangements consistent with new charges taking effect from 1 April 2010.

Governance arrangements

5.3. DNOs are required to develop common governance arrangements, according to the criteria set out in the new proposed licence conditions, for submission to the Authority by 1 September 2009. DNOs will need to work together to draft these arrangements and to decide on the most appropriate mechanism (whether through formal consultation or working groups, for example) for obtaining the views of interested industry parties.

5.4. Ofgem staff will, if invited, attend meetings with the DNOs and interested parties on this matter. In order to help the progress of the project, and if requested by DNOs, we would consider providing 'minded to' decisions on material issues arising should DNOs wish to understand how they are progressing towards securing approval of the governance arrangements. However, it is the responsibility of DNOs to lead this workstream and ensure timely delivery.

Areas for further development

5.5. DNOs are required to work together to action the areas highlighted for further development in Chapter 3 and Appendix 2. The output of this joint working will be a common approach to the outstanding areas for incorporation into the common charging methodology by 1 September 2009.

5.6. DNOs are expected to obtain the views of other interested industry parties on these matters. It is for the DNOs to consider what existing or new fora are appropriate for such discussions. This is a stream of work in which the use of consultants could greatly help DNOs to achieve the project deadline. The terms of reference attached at Appendix 3 envisages this support. We will discuss the scope of the required consultancy support with DNOs at an early date. In parallel, DNOs will work collectively or individually as they choose, to develop a range of tools and products to assist customers to better predict and manage the volatility associated with the charging methodology as discussed in Chapters 1 and 3.

5.7. Ofgem will work with the DNOs to ensure that price control policy and associated special licence conditions marry up with common methodology charging arrangements along with connection charging policy. Ofgem will attend DNO working groups to discuss the areas of the methodology for further development. Again, in order to help the progress of the project, and if requested by DNOs, we would consider providing 'minded to' decisions on material issues arising in areas for further development should DNOs wish to understand how they are progressing towards securing approval of the common methodology.

Implementing the common methodology

5.8. Implementing the methodology falls into two stages. Firstly, drafting a generic template(s) that takes the detail of the methodology contained in Appendix 2, to the next level of detail. Secondly, DNOs populate these templates to arrive at the calculation of charges.

Stage One

5.9. Consultants will develop the detailed templates for submission to Ofgem by 19 December 2008. A proposed terms of reference for this work is set out in Appendix 3. Consultants will require input from DNOs and we expect that the consultant will need to meet regularly with DNOs as a group and individually to obtain the information and feedback they require to establish templates that can be used to calculate charges. It will be necessary to set up a common use of system charging working group attended by charging experts from DNOs and Ofgem for this purpose. It is for DNOs to structure these meetings.

5.10. We are committed to supporting this development work. Consultants will need to report directly to us on progress. In order to help the progress of the project we would consider providing 'minded to' decisions on material issues arising should DNOs wish to understand how they are progressing towards securing approval of the common methodology. Once the template has been developed, Ofgem will review it and ensure that it is an appropriate reflection of the common charging methodology principles and assumptions as set out in Appendix 2 of this document. We will provide feedback to the DNOs on this matter in January 2009.

Stage Two

5.11. Once the generic charging template has received this review, each DNO will populate the templates to produce illustrative charges for their networks. In this stage, we expect DNOs to be proactive in discussing issues that arise with Ofgem and proposing solutions, as discussed in Chapter 1. As set out in that Chapter, it may be that a number of DNOs face similar issues in applying the template. We would expect DNOs to continue to work together and with Ofgem to identify these common issues and to work up any changes required to the common charging methodology and the template to address them.

5.12. Each DNO is required to bring forward the common charging methodology and a full set of illustrative charges to the Authority by 1 September 2009. DNOs may collectively consider it appropriate for the consultants used in Stage One to be retained for this stage of the implementation process.

Tasks	Date
Ofgem decision on form of common charging methodology (this document)	1 October 2008
Start of 28-day statutory consultation on licence condition changes (CLM)	1 October 2008
Ofgem to consider responses to statutory licence consultation	October 2008
Ofgem to issue licence modification to licensees and implement licence condition changes	1 November 2008
Industry to establish common methodology implementation working group	October/November 2008
Consultants appointed	October/November 2008
Industry to establish working group to agree detail of governance arrangements for common methodology	October/November 2008
Consultants provide report and suite of spreadsheets to enable charge calculation to DNOs and Ofgem	19 December 2008
Ofgem to provide feedback on spreadsheets and report	January 2008
DNOs to populate spreadsheets	January – August 2008
DNOs to liaise with Ofgem and consultants on issues arising from implementation	January – August 2008
DNOs to submit to Ofgem common methodology along with full set of illustrative prices	1 September 2009
DNOs to submit governance arrangements to Ofgem for approval	1 September 2009
Potential consultation and assessment of charging impacts	October-November 2009
Ofgem to approve common methodology	31 December 2009
Aproved methodology to take effect	31 December 2009
DNOs publish indicative prices on basis of common methodology	31 December 2009
Authority to revoke each DNO's existing use of system methodology	31 March 2010
Implementation of common charging methodology for use of system charging	1 April 2010

Appendices

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Appendix 1 - July Consultation Questions and Responses

1.1. In its July decision and consultation letter (reference 104/08, 'Delivering the electricity distribution structure of charges project: decision on a common methodology for use of system charges from April 2010, consultation on the methodology to be applied across DNOs and consultation on governance arrangements'), Ofgem consulted on a number of issues as set out below:

- How to achieve commonality (the letter explained the reasons for our decision to require a common methodology from April 2010 and consulted on how to achieve such commonality);
- The pros, cons and impacts of the different charging methods developed to date, and asks for views on Ofgem's intention to choose the approach to be applied and developed as the common methodology;
- Governance arrangements associated with a common charging methodology;
- Timescales and processes for the project between now, 1 October 2009 submission and 1 April 2010 price changes; and
- The features required of any licence changes to capture commonality and governance arrangements.

1.2. Ofgem sought the views of respondents about a number of questions as set out below:

- Whether respondents agree that we should specify the common methodology to be applied across DNOs;
- The pros, cons and impacts of each model;
- Governance arrangements and various options set out in the July letter;
- The proposed processes set out in the July letter; and
- Whether there are any other matters we need to consider in light of our decision on a common charging methodology.

List of Respondees

List	Name
1	Bizz Energy
2	British Energy
3	British Gas
4	CE Electric
5	Central Networks
6	CHP Association
7	EDF Energy Networks
8	Energetics
9	Ener.G group
10	energywatch
11	Energy Networks Association
12	ENW
13	E.On
14	ESP Electricity
15	Furong Li and David Tolley (DLT Consulting)
16	Gaz de France
17	MCM Consulting
18	National Grid
19	Renewable Energy Association
20	RWE Npower
21	Scottish Power Energy Networks
22	Scottish Power Energy Retail
23	Scottish Renewables Forum
24	Scottish and Southern Energy
25	Western Power Distribution

Summary of Responses

1.3. Responses received by Ofgem which were not marked as being confidential have been published on Ofgem's website www.ofgem.gov.uk. Copies of non-confidential responses are also available from Ofgem's library.

Introduction

1.4. Here we provide a summary of the responses received to our July 2008 consultation in terms of the pros, cons and impacts of the various charging models presented. These responses have been considered in Chapter 2 in our decision on the models to be adopted.

Background

1.5. In our July document we presented an impact assessment setting out, with the information available to us, the pros, cons and impacts of the various approaches to charging at EHV, HV and LV across demand and generation customers. We asked for views on this, including a specific request to DNOs in their responses to identify and quantify impacts and to provide evidence justifying their preference for specific charging assumptions over other assumptions.

Consultation Responses

Network operator responses

DNOs

1.6. CE Electric (CE) support the LRIC model approach, stating that it "is the best methodology to adopt as it most closely aligns to, and provides a pragmatic balance of, the principles that have been developed to underpin the SoC[15] project and provides the purest economic signals". They do not support the forward cost pricing (FCP) approach advocated by Scottish Power Energy Networks (SP), Central Networks (CN) and Scottish and Southern Energy Power Distribution (SSE)[16] as they argue that it is more labour intensive to implement.

1.7. Further to this CE suggest the G3 package has some undesirable properties, for example the use of RRP[17] data which is not forward looking, a lack of symmetry between demand and generation which will distort cost signals, and the use of the 87% load factor in determining reinforcements which they believe will introduce instability in charges. In their response CE also comment on Electricity North West's (ENW) work on what ENW call an improved incremental cost related pricing (ICRP)[18] model (IICRP). CE argue that IICRP is still in the development stage so they are unable to assess the costs and benefits associated with this model. Alongside these points CE raise concerns about the magnitude of abortive costs across DNOs from the structure of charges project.

1.8. EDF Energy Networks (EDF) support the LRIC model approach at EHV level indicating that the benefits of this are specified in the 2005 Bath University report[19]. They favour it against other approaches on the basis that it provides stronger locational signals, treats generation and demand equally, and is more open to future

[15] Structure of charges.
[16] These three groups of companies collectively call themselves 'G3'.
[17] Regulatory reporting pack data. This is regulatory information supplied to Ofgem on a yearly basis.
[18] National Grid use an ICRP model to determine charges for using the transmission system.
[19] Bath University study, December 2005, 'Network benefits from introducing an economic methodology for distribution charging' http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistChrgs/Documents1/12617-1206a.pdf.

development at HV and LV levels of the network. They also support DRM[20] at lower levels.

1.9. Western Power Distribution (WPD) support LRIC for EHV level charging and DRM for HV and LV charges. They argue the stability of prices under LRIC method is a function of the stability of the input assumptions to the model. They suggest greater stability can be achieved by smoothing any 'noise' on these input assumptions. They do not support G3's FCP approach as they argue that incremental costs between zones are not comparable. Neither do they agree with the G3 approach to generator charging as they argue the use of a 'typical' generator is not cost reflective and that fault level costs are best captured in the up-front connection charge. WPD do not support an ICRP-type method either as they suggest the use of incremental cost expansion does not reflect the lumpy nature of network investment on the distribution system. WPD also criticise the ICRP model's inability to take account of utilisation, commenting that it appears inappropriate that on long stretches of radial networks ICRP produces high charges when utilisation is low.

1.10. SP support their FCP approach, arguing that it is drawn from the principles of LRIC, but that it has more desirable economic properties. These include flexibility under different assumptions for growth and appropriate cost recovery. SP also argue that their model retains flexibility for future development, for example to take account of changing patterns of consumptions and to enable it to develop a more significant degree of locational charging.

1.11. SP are critical of the LRIC approach and state that it leads to excess pricing and weak economic signals under some local conditions. They are also concerned that the model produces high charges at low growth rates. They highlight LRIC's inability to consider generation fault level costs. In terms of the SoC project they are unclear about the level of benefits from the project and estimate costs will be higher than £7m across DNOs due to factors such as potential billing system changes which they argue have not been considered by Ofgem. They suggest that a full financial impact assessment should be undertaken once the scope of the project is known.

1.12. SSE considers that the G3 model is the only one which would fully meet the relevant principles set out in Ofgem's April 2008 consultation document. They are strongly of the view that generation (certainly pre April 2005 generation) should not pay distribution use of system charges.

1.13. In addition SSE are strongly critical of the LRIC approach. They believe that the errors in demand costs derived from LRIC and reflected in generator benefits inevitably mean that the methodologies fail to facilitate competition. SSE further consider that a LRIC based methodology is incompatible with the current shallowish connection charging methodology. They state that the shallowish connection boundary already provides a locational signal. If LRIC is adopted, they suggest that the resulting "pancaking" of charges will mean that incorrect economic signals are provided to both demand and generation.

[20] The distribution reinforcement model (DRM). This is currently used (in various guises) by a majority of DNOs.

1.14. SSE also criticise the constant growth rate to all future times within LRIC. They claim that the ability to forecast growth rates well into the future, particularly when energy prices are extremely volatile, is limited. The growth rate in LRIC is extremely important as more weight is placed on reinforcement cost in the longer term. SSE argue that you cannot accurately predict the growth rate in 20, 30, 40 years time and therefore that the charges produced for reinforcement calculated to occur in these years are inaccurate.

1.15. CN strongly advocate the G3 methodology and list many properties which they consider desirable. These include that:

It uses an approach that is both forward looking and incremental;

- It provides different location price signals to existing and potential EHV demand and generation customers;
- It employs granular data on growth rates for network groups at all levels, taken from published sources; and
- It recognises and reflects both the costs imposed and benefits afforded by demand and generation customers in these different groups.

1.16. CN also strongly criticised LRIC. They do not believe that LRIC's charging functions work for highly utilised or low growth networks. CN comment that this could result in potentially 'abusive' prices being calculated. Specifically, CN believe that implementation of LRIC could result in competition law breaches due to charges (at low growth rates) recovering in a single year revenue which amounts to many time the values of the assets used.

1.17. CN go on to say that LRIC methods do not take account of all relevant reinforcement costs as they ignore fault level costs. CN claim that academics are in agreement that the inclusion of fault level costs is a significant step forward and yet it is unclear whether the LRIC nodal basis can accommodate fault level costs. Further CN, were concerned that the use of a 40 year annuity period would dampen down the economic message being produced.

1.18. ENW advocate their own approach stating that they believe that ICRP methods provide a better reflection of the costs where load growth is not as significant unlike FCP and LRIC. They suggest that LRIC results in high nodal charges and is too sensitive to assumptions. More generally they argue that a common approach to charging prevents innovation and creates risks to the delivery of a charging methodology for the new price control period.

National Grid

1.19. National Grid agree with the development of a common methodology. They say it will bring more efficient development of future changes to the methodology and that commonality will aid understanding and transparency and thereby reduce analytical costs across the industry. They note that offshore transmission arrangements mean that National Grid as GBSO will become a DNO customer and believe that commonality will help them understand DNOs' charges. They suggest that DNO charging arrangements should reflect transmission charging arrangements as far as practicable.

IDNOs

1.20. Energetics note issues with both LRIC and G3's proposal for EHV level charges. They are concerned about the apparently sharp incremental cost signals on low growth/highly utilised networks, but seem to think that on the whole a 'corrected' LRIC produces a more robust and transparent set of charges. They also set out pros and cons of the HV/LV demand charging models.

1.21. ESP Electricity support a common IDNO charging methodology and ask that IDNOs be able to participate fully in the development of commonality. They support the model which will deliver the most stable charges and in view of this they want a sunset clause that prevents further review until 2015 as well as charge capping. They suggest that the G3's FCP approach (at EHV) would provide more stable long-term charging.

Supplier responses

1.22. Bizz Energy, a small supplier, are principally concerned with predictability and stability. They think simple and stable charging models will do the most to promote competition in the small supply market. They would like to see changes in the level of charges capped to 5% year on year. British Energy also argue that stable prices are their key concern. Gaz de France did not advocate a specific model, but supported an approach which provided stable and transparent charges. They suggested capping charge changes year on year, common time banding and a more uniform approach to embedded generation charging.

1.23. British Gas do not comment on specific models, but set out that they favour an approach which prioritises simplicity/transparency over cost reflectivity where such trade-offs exist. They favour a model which is based as far as possible on publicly available information and which minimises the use of judgement in the formulation of charges. They set out that they will need access to the model in order to predict future charges and make changes to reflect different scenarios.

1.24. RWE Npower are concerned about how LRIC responds to low and negative growth levels, and are concerned that FCP does not provide symmetrical outcomes between demand and generation. They support the RRP Cost Data approach for HV/LV charging as they believe it provides users with the opportunity to estimate future charges. They also like the G3 approach to scaling in terms of it incorporating cost allocation with a fixed adder.

1.25. E.On Energy believe that the methodology selected should be transparent to users. They also suggested that a common application of the DRM should be applied across DNOs at HV/LV level.

Generator responses

1.26. Ener.G were unable to comment categorically on models given their complexity. They consider that more time is needed for such an important multi party decision to be made, and for Ofgem to deliberate on. They question renewable generation's elasticity of response to locational charging signals. They favour the production of more transparent models, suggesting publication of a map giving colour coded indicators of where capacity constraints exist and where charges are likely to be highest.

1.27. The Renewable Energy Association did not comment on specific aspects of the models. They were unclear as to why EHV and HV and LV could not have the same charging arrangements. They set out that they believe there is a trade off between the cost reflectivity and stability of charges.

1.28. The Scottish Renewable Forum stated their concerns over the use of LRIC or ICRP approaches, suggesting either will result in unpredictable charges. They argue this will have detrimental effects for generation. They support FCP in terms of it providing long term stable charges.

Other interested parties

1.29. DLT Consulting and Furong Li argue it is inevitable that there will be tensions between the various principles that have been identified for a distribution use of system charging methodology. They state that the LRIC approach offers the best prospects for satisfying these principles in the round, and providing a robust basis on which networks can develop economically. More specifically they set out that LRIC is an incremental approach whereas G3's FCP method is a total cost approach. As such, they believe that LRIC will "tend to encourage a more economically efficient use and development of the distribution network." They believe that although a considerable amount of research has been undertaken for LRIC it is still in a evolving state. However they consider that LRIC is preferable to FCP as they believe, for example, the use of 10 year horizons will introduce instability.

1.30. energywatch's response states that most customers and business are not responsive to price signals and so question the importance of locational pricing. They argue the main benefits of commonality will come from having a simple, predictable, and transparent charging methodology and that this will enable suppliers to most accurately predict charges. However, they suggest uncertainty will result in suppliers adding a risk premium to prices to consumers. They also suggest Ofgem should consider allowing a transition period to mitigate significant step changes in the level of charges.

1.31. The MCM response provides a detailed analysis supporting G3's FCP model. They consider that one of the most important considerations is how each model encourages new generation. They state benefits from the 10 year horizon as reducing distortions over a longer asset life and that FCP provides stronger signals for capacity than LRIC. More generally, this response questions the ability of charges to influence the location decisions of generation and demand and suggests there is a lack of an economic basis for LRIC.

The response from the Energy Networks Association (ENA) mentions that a considerable amount of costs will have been stranded by each DNO on development of long term charging arrangements to date. They suggest this could be in the region of £0.5m per DNO.

Appendix 2 – Common use of system charging methodology: principles and assumptions

Introduction

1.1. This Appendix sets out the fundamental principles and assumptions behind what will become the common distribution use of system methodology (CDCM)[21]. Each part of the methodology is taken in turn, covering EHV, HV and LV charging for demand and generation customers as well as scaling and reactive power charging. We expect this to form the basis of the common methodology. Areas for future development by DNOs are highlighted in this appendix in italics. In terms of areas for further development this Appendix should therefore be read in conjunction with Chapter 3.

EHV demand and generation charging

Summary

1.2. EHV demand and generation charges are calculated based on the long-run incremental cost (LRIC) model.

1.3. The LRIC model calculates nodal incremental costs. These costs represent the brought forward (or deferred) reinforcement costs caused by the addition of an increment of demand or generation at each network node. The method models the impact changes in users' behaviour have on network costs.

1.4. In particular, the LRIC model takes account of the effects a change in user behaviour has on the network by using AC power flow analysis, which enables the calculation of the time needed before elements of the network require reinforcement and subsequently the net present value (NPV) of the future costs of reinforcement. The incremental cost is equal to the difference in the NPV of reinforcing under existing conditions and when an increment of new demand or generation is added.

1.5. EHV demand and generation charges are calculated in the following stages: AC power flow analysis, calculation of incremental costs including the consideration of peak and off-peak demand conditions, scaling to recover allowed revenue and then the calculation of final charges.

[21] This Appendix is in line with the proposed collective licence modification which sets out that the CDCM be developed so as to conform to the fundamental principles and assumptions set out by the Authority on or before 1 October 2008. These assumptions and principles are set out this decision and predominantly (though not exclusively) in this Appendix. The proposed licence drafting in the attached statutory notice sets out that DNOs have to develop the CDCM and submit it to the Authority by 1 September 2009 for designation.

Sole use assets

1.6. The EHV connections on a distributor's network include single customers connected to the system using assets that have been sized to their connection requirements. Costs for these assets should be excluded from the calculation of incremental costs if they have already been paid as part of a connection charge. Replacement and operation and maintenance costs for these assets should also be excluded from the calculation of incremental costs, but may be incorporated into a customer's final charge ('sole use asset charges').

Power Flow Analysis

1.7. Power flow analysis calculates the effects of adding an increment of demand or generation to the distributor's network. In particular, it calculates the power flows passing over the various assets of the distributor's network under base and incremental conditions using peak (typically during the winter period) and off-peak (typically during the summer period) demand data.

1.8. The power flow analysis should calculate the following nodal based values:

- Base power flows using peak and off-peak demand data, and
- Incremental power flows using peak and off-peak demand data.

1.9. Power flow analysis uses a number of processes and assumptions as follows:

- A representation of the entire EHV network[22] captured using appropriate power flow modelling software. The modelled network should be based on the network expected to exist and be in operation in the first regulatory year that charges are being calculated for, based on the distributor's long term development statement.
- Nodal demand and generation data should be used, which is based on actual metered network usage data that is recovered from the distributor's Supervisory Control and Data Acquisition (SCADA) (or equivalent) system. In particular:
    - Demand data - For the peak demands, the model uses demands consistent with those used to assess reinforcement. This includes diversity to allow a complete EHV system model to be run. Off-peak demands are taken as being a percentage of peak demands. This percentage is derived for each grid supply point (GSP) and applied to the demands supplied by that GSP.
    - Generation data – for the peak period generation is zero unless it is deemed to contribute to network security in accordance with Engineering Recommendation P2/6[23]. The generation export used for the off-peak

[22] The EHV network consists of all assets between the 132kV level through to, and including, the 33/11kV level.
[23] Engineering Recommendation P2/6 is intended as a guide to system planning and is published by the Energy Networks Association (http://2008.energynetworks.org). It takes into account the results of extensive reliability studies using fault statistics and risk analysis and the relationship of these to the costs of system reinforcements, including the effects on losses.

period is the maximum agreed export capacity. These are the broadly similar to the assumptions that are used by distributors when investment planning.
    - Distributors should cleanse demand and generation data so that it is representative of typical network usage. That is, anomalous power flows, which represent, for example, demand levels at a time when the network is experiencing an outage, should be removed from the data set and the effects of load management schemes should be taken account of.
- AC nodal power flows are modelled. Power flows should be calculated for peak and off-peak base conditions ($BasePowerFlow(MVA)$) and for peak and off-peak conditions plus an increment of demand or generation ($IncPowerFlow(MVA)$).
- Increment
    - A ±0.1MW increment should be used in relation to calculating the active demand and generation elements of the incremental power flows, assuming that the power factor for demand is 0.95 and unity for generation.
- Growth Rate
    - A single underlying network growth rate is used to assess the timing of future reinforcement for demand and generation charges. It represents the long run growth of all distributors' networks and is set to 1% growth per annum.
    - To facilitate predictability and stability, the growth rate is used throughout the model and as with all assumptions, distributors should keep this growth rate under review. As a minimum, the rate should be reviewed and reset when distributors' price controls are reviewed every five years.
- A pair of Security Factors should be determined for each asset using a full N-1 contingency analysis assuming peak and off-peak demand conditions. These factors are used to determine the usable capacity of network assets during peak and off-peak conditions. They are recalculated each time the network is changed or new load estimates used.
    - Power flows under N-1 contingency conditions are used to calculate Security Factors.

Calculation of incremental costs

1.10. The incremental cost of reinforcing a node is the difference in the NPV of reinforcing it under base conditions and with an increment of demand or generation added.

1.11. The nodal incremental cost is therefore calculated using the following formulae:

$$IncrementalCostAtNode = \sum_{i=1}^{B} \Delta Ci$$

Where ΔCi is the change in reinforcement costs of the asset in branch *i* when an increment of demand or generation is added to the node. *B* is the number of branches connected to the node.

$$\Delta Ci = [NetPresentValue(inc) - NetPresentValue(base)] \times AnnuityRate$$

$$NetPresentValue(inc) = \frac{CostOfReinforcementSolution}{[1 + DiscountRate]^{YearsToReinforcement(inc)}}$$

$$NetPresentValue(base) = \frac{CostOfReinforcementSolution}{[1 + DiscountRate]^{YearsToReinforcement(base)}}$$

$$AnnuityRate = \frac{DiscountRate}{1 - \left[\frac{1}{[1 + DiscountRate]^{AnnuityPeriod}}\right]}$$

$CostOfReinforcementSolution$ is the modern equivalent asset value (MEAV) of reinforcing the particular asset, bearing in mind the requirements of similar historic projects[24]. This cost is the same under both base and incremental conditions.

$DiscountRate$ is equal to the (pre-tax) cost of capital set by Ofgem as part of distributors' current price control.

$AnnuityPeriod$ is the period over which costs are annuitised. This period is set to 40 years and represents the typical life of an asset.

1.12. Power flows and asset capacities calculated by the power flow analysis under base and incremental conditions are fed into the following formulae to calculate the time to reinforcement for each asset under base and incremental conditions.

$$YearsToReinforcement(base) = \frac{\log AssetCapacity - \log BasePowerFlow(MVA)}{\log[1 + GrowthRate]}$$

$$YearsToReinforcement(inc) = \frac{\log AssetCapacity - \log IncPowerFlow(MVA)}{\log[1 + GrowthRate]}$$

1.13. A pair of incremental costs is calculated for each asset using peak and off-peak demand power flows (a ‘peak incremental cost and ‘off-peak incremental cost).

Consideration of peak and off-peak demand conditions

1.14. Once incremental costs are calculated for each branch using peak and off-peak demand data, those costs that relate directly to each customers’ use of the network and that drive the need to reinforce the network are summed together.

[24] Distributors should use the specifications and costs of similar, past reinforcement projects as a means for determining the requirements and costs of a particular future reinforcement project.

1.15. In particular, for site-specific EHV demand customers, their incremental charge is calculated taking account of either peak and off-peak network conditions as follows:

- Determine whether reinforcement is driven by peak or off-peak network demand conditions for each branch used by the demand customer. The period that is deemed to drive reinforcement is the period with the highest positive associated incremental cost signal.
- Where peak conditions drive reinforcement, the branch charge is the peak incremental cost for the particular asset being considered multiplied by the 'peak charging demand'[25].
- Where off-peak conditions drive reinforcement, the branch charge is the negative of the off-peak incremental cost for the particular asset being considered multiplied by the 'off-peak charging demand'.
- The customer's incremental charge is the sum of all branch charges[26] which are used by the customer (relevant branches).

1.16. For site-specific EHV generation customers, their incremental charge is calculated as follows:

- Determine whether reinforcement is driven by peak or off-peak network demand conditions for each branch used by the generation customer. The period that is deemed to drive reinforcement is the period with the highest positive associated incremental cost signal.
- Where off-peak conditions drive reinforcement, the branch charge is the peak incremental cost multiplied by the agreed export capacity.
- Where peak conditions drive reinforcement, the branch charge is the negative of the peak incremental cost multiplied by the level of demand expected to contribute to network security as set out in engineering recommendation P2/6.
- The customer's incremental charge is the sum of all branch charges[27] which are used by the customer (relevant branches).

1.17. For individual EHV connected customers, the peak demand used for charging purposes ('peak charging demand') should be based on an average of the customers' demands that coincide with GSP peak demand during the months that surround the GSP peak demand. The off-peak demand used for charging purposes ('off-peak charging demand') for individual EHV customers is an average of the customers' lowest level of demand that coincides with the lowest GSP demand recorded during the months that surround the lowest GSP demand. Where a customer's connection is new or significant changes have been made to the agreed capacity a best estimate will be used for the 'peak charging demand' and 'off-peak charging demand' taking into account the typical ratio of agreed supply capacities to charging demands for existing customers.

[25] Peak and off-peak charging demands are described in more detail in paragraph 1.18.
[26] Only assets that experience a change of greater than 1kVA in the power that flows across them are used in the calculation of branch charges.
[27] Only assets that experience a change of greater than 1kVA in the power that flow across them are used in the calculation of branch charges.

1.18. When calculating the peak and off-peak charging demands, distributors should use the most recent, available and complete set of demand data.

The demand used for charging purposes for connections to other licensed distributors needs further consideration by distributors as part of their development work for IDNO charging.

Revenue Scaling

Summary

1.19. In accordance with their price controls, licensed distributors are allowed to recover revenue that covers their capital and operational expenditure requirements.

1.20. Given forecast network usage, the incremental charge will recover a proportion of a distributor's allowed revenue. This amount may be over or under the overall allowed revenue.

1.21. Consequently, revenue scaling is used to regulate the incremental charges so that they recover revenue that is equal to the distributor's allowed revenue.

Fixed adder approach

1.22. In relation to EHV charges, a fixed adder revenue scaler should be used to ensure that EHV charges do not significantly over or under recover revenue. The adder will be in £/kVA.

1.23. To calculate the size of the EHV demand fixed adder in relation to demand allowed revenue, the following steps are followed:

- Total demand allowed revenue is split between the EHV network and lower voltage networks using MEAVs. This gives an EHV allowed revenue and an HV/LV allowed revenue.
- Asset quantities used for this evaluation should be consistent with those contained in distributors' Regulatory Reporting Tables together with MEAVs used for long term investment planning.
- Based on the charges calculated in accordance with paragraphs 1.16 and 1.17, forecast revenue from EHV site specific customers is calculated.
- The revenue forecast is subtracted from the EHV allowed revenue, which leaves an amount of revenue yet to be recovered.
- The unrecovered revenue is divided by the forecast winter demand (kVA) to give a unit rate fixed adder (£/kVA), which is incorporated into customers' final tariffs.

1.24. The generation incentive set out in each distributor's price control sets the allowed revenue that may be recovered from connected generators. Generator charges are adjusted as follows: *fixed adder approach, further detail to be worked* *up. Note the interactions with the price control review and associated special licence conditions.*

Calculation of final charges

1.25. Final site-specific demand charges consist of:

- The customers incremental charges,
- A fixed adder,
- Sole use asset charges, and
- The allocation of network rates[28] and NGET exit charges.

1.26. Site specific generator charges consist of:

- The customers incremental charges,
- A fixed adder,
- Sole use asset charges, and
- The allocation of network rates.

The form of the final charge (including common tariff structures) is to be further developed by distributors. This needs to incorporate a reactive power charge for customers with a power factor worse than 0.95.

1.27. EHV customers final charges will recover a proportion of the total EHV allowed revenue. The remainder is the Residual Value, which is passed down into the DRM. Further detail is provided in the following paragraphs.

Interaction between LRIC and DRM

1.28. A LRIC methodology applies at EHV and a DRM methodology at HV/LV. There is a relationship between these two methodologies as HV/LV customers place demands on the EHV network. In order to ensure that this impact is captured within charges, certain aspects of the LRIC charge are passed into the DRM yardstick. Costs for voltage levels 132kV down to 33kV/11kV substation from the LRIC model are dropped into the DRM at the 33kV/11kV transformation level. The interaction works as follows:

- The residual value is calculated by taking the target income of EHV assets (total revenue split by the proportion which the EHV MEAV comprises of the total network MEAV). The total amount recovered from EHV customers is then subtracted from this amount.
- The remaining cost to be recovered on the EHV network (the residual value) is then divided by the difference between the total EHV customer KVA and total EHV kVA to give a £/kVA value which represents what the HV/LV network should pay for its use of the EHV system.

[28] Network rates represent costs incurred by the distributor, for example in relation to council or corporation tax.

- The £/kVA value is then divided by the assumed DRM power factor of 0.95 to provide a £/kW value.
- The £/kW value is then placed into the 33kV/11kV transformation level within the DRM yardstick.

HV/LV demand charging

DRM

1.29. Charges for HV/LV demand will be calculated using a distribution reinforcement model (DRM).

1.30. A representative network which comprises of the assets required to accommodate a 500 MW increment to each distribution service area (DSA) is developed as a scenario. This is based on the topography and demographics of the expected network and how this network is likely to develop over time. This representative network excludes what would be paid for in connection charges under the current charging regime. For example the LV service cable is excluded from the representative network to the extent that they are covered by connection charges. 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.

1.31. The network costs (calculated in terms of their modern equivalent asset value (MEAV)) of accommodating this incremental network is calculated for each of the following transformation and voltage levels[29]:

- HV circuits
- 11kV/LV Substations
- LV circuits

1.32. This produces a cost at each transformation at each of the voltage levels noted above. This cost is then allocated to the following minimum number of customer classes[30]:

- NHH Domestic Unrestricted (PC1)
- NHH Domestic Restricted (PC2)
- NHH Non Domestic Unrestricted (PC3)
- NHH Non Domestic Restricted (PC4)
- NHH Unmetered Supplies (PC 1-8)
- NHH LV (PC5-8)

[29] Please note that for EHV voltage and transformation levels the costs which HV/LV users place on the EHV network are calculated within the LRIC methodology. The incremental costs from the EHV assets which HV/LV users utilise are fed down into HV/LV charges. The precise mechanics of this approach are described in detail above.
[30] We would expect any charging methodology to include these customer classes but *the precise details are subject to development, for example IDNO tariffs.*

- HH LV
- HH HV

1.33. This allocation is calculated by looking at the average consumption of an individual customer in each customer class. This average is then multiplied by the number of customers in each customer class to provide the overall annual consumption (or load) of the entire customer class at the voltage level of connection.

1.34. Loss adjustment factors are used to scale up the load at the voltage of connection to the load which is placed on the transformation levels and voltage levels above the voltage of connection.

1.35. Coincidence factors are then used to assess the contribution each customer class comprises to overall network peak demand. Finally the entire sum is divided by the load factor of the network.

1.36. These series of calculations are shown by mathematical formula below:

$$CustomerclassSystemMaxDemand(kW) = \frac{1000 \times AnnualConsumption(MWh) \times CoincidenceFactor \times [1 + Losses]}{Loadfactor}$$

1.37. These calculations are repeated to produce a peak system demand at each voltage and transformation level for each customer class.

1.38. The network costs at each voltage and transformation level are then associated with the addition of the 500 MW increment are then split by the proportion which each customer class contributes to the peak network demand.

1.39. These costs are then annuitized over a 40-year period using the DPCR cost of capital. This produces a yardstick unit cost in p/kWh.

1.40. In order to calculate the contribution of each customer class to the peak network maximum demand, the following data is required:

- Forecast units distributed or consumption (MWh);
- Forecast agreed capacities (kVA);
- Forecast customer numbers;
- Load factors (kWh/year/kW) – this is the forecast annual consumption for the customer group divided by the maximum demand;
- Coincidence factors – this is the ratio of the maximum demand at the time of system peak divided by the customer group's maximum demand;
- Loss percentage – this is a calculated value based on published loss factors for each half-hour and the actual consumption in that half-hour; and
- Power factor – a value of 0.95 is used for all loads to convert from kW to kVA.

1.41. This data is updated (i.e. the new, latest forecast inputs used) each time a distributor updates its charges.

1.42. Operational and Maintenance (O&M) costs are also included within the DRM. The rate for O&M is calculated as a percentage based on forecast O&M costs and are calculated for the next charging year. These costs are then calculated as a % of the total MEAV asset cost. As with the calculation of network costs the DRM looks at the contribution each customer class makes to peak network demand. This provides a proxy as to the assets which each customer class uses. The ratio of which O&M costs comprise of total cost is then applied to the assets each customer class uses. This provides a cost figure for each voltage and transformation level. As with the network costs, these are then split into yardsticks by looking at the contribution each customer class makes to peak network demand at each voltage level. Again once these costs have been allocated, they are annuitized over 40 years.

1.43. The yardstick costs produced are then allocated to both the unit charge (p/kWh) and the fixed charge (p/MPAN/day). The precise method in which this allocation works will be made clear in the common spreadsheet charging templates which Ofgem are committed to help DNOs develop.

1.44. This calculation produces a £/kW/year charge. This is divided by an assumed power factor of 0.95 in order to produce a £/kVA/year charge.

The split between day and night charges and the calculation of capacity charges must also be determined and we consider that this detail will be included in the final template which Ofgem is committed to developing alongside DNOs.

The form of the final charge (including common tariff structures) is to be further developed by distributors, incorporating a reactive power charge for customers with a power factor worse than 0.95.

1.45. Excess reactive power charges are levied for those customers with a power factor of less than 0.95. The charges are derived from the same network yardstick costs used for other DUoS components.

1.46. For each customer class (at the respective voltage level), an excess reactive unit charge may be derived from the incremental change in the yardstick[31] (for a defined change in power factor) divided by the incremental change in the kVAr (for the same change in power factor), adjusted by the customer class load factor to give the cost of an additional reactive unit (in pence/kVArh).

1.47. For clarity this calculation is described below in six steps. The first three steps derive the costs of delivering a kWh at different power factors. The following three

[31] The yardstick value used in the reactive power methodology excludes the element of the yardstick used in the calculation of the availability charge.

steps focus on the incremental effects of varying power factor, in terms of cost and unit volume, in order to derive prices. For each customer class at the respective voltage level:

i. Calculate the yardstick excluding the fraction used in the availability charge calculation (in £/kWpa), recognising that this assumes a power factor of 0.95.

ii. Convert this to pence/kWh by dividing by the kWh/kW pa for the customer class and multiplying by one hundred.

iii. For the range of power factors from 0.95 through to 0.05 (in increments of 0.05), derive the “adjusted pence/kWh” by multiplying the “yardstick pence/kWh” (calculated in step two above) by the ratio of 0.95 (the network design power factor) to the new power factor.

iv. Derive, from the table produced in step three above, the incremental cost, in pence/kWh, of moving to each of the tabulated power factors, thereby defining power factor bands.

v. Calculate, and tabulate, the incremental change in reactive units per kWh (kVArh/kWh) for the same range of power factors bands.

vi. Divide the incremental cost effect (shown in step four above) by the incremental reactive units (shown in step five above) to provide the excess reactive unit charge (in pence/kVArh) for each power factor band.

Scaling

1.48. Scaling is required to align the total yardstick charges with allowed revenue from price control. A fixed adder should be used to scale up the revenue recovered through charges to allowed revenue. At a high level this works by splitting total revenue by the MEAV of the HV/LV assets to obtain a target recovery for HV/LV. The difference between the allowed revenue and recovered revenue is then allocated to customers on a kWh or p/MPAN basis.

Detail of fixed adder application to be further worked up by DNOs. Again, note interaction with generation side.

HV/LV Generation

Note that generator use of system charging for “existing” (i.e. pre-April 2005) generators is being taken forward under the price control review.

1.49. The charges allocated to generators are applied using the same principles as those used for demand tariffs. Where HV/LV demand incremental costs are offset or deferred the charge will be negative pre scaling. Generators are also liable for use of system charges on their demand requirements.

1.50. Charges for generators connecting at HV or LV will be calculated in accordance with the assumption that generators provide benefits in deferred investment and this should be reflected in the charges.

1.51. The network is assumed to be demand dominated. Credit will be provided for offsetting demand on the distribution network above the voltage of connection.

1.52. The calculation of the charges for HV/LV generation that exports onto the distribution system is explained [above] in accordance with demand charges. The DRM methodology defines the costs incurred or credited to exporting HV and LV distributed generation.

1.53. It is assumed that the generator will not cause additional reinforcement costs as there will be even dispersion of generation across the network. A generator will offset demand and provide benefits to higher voltage levels by delaying reinforcement. To reflect the benefits a generator provides, a negative sign will be applied to the yardsticks when calculating the generator charges.

1.54. The level of the charge will be determined in accordance with universal P2/6 security standards (F-Factors). Where a generator is defined to be a non-intermittent type of generation, the generator will be assigned an F-Factor based on its generator type and number of units in the generating station that determines the impact of generation on the distribution network. Where a generator is defined to be an intermittent type of generation, the generator will be assigned an F-Factor based on the period of continuous generation (i.e. Persistance) and not affected by the number of units at an individual site.

1.55. The values for the generator F-Factors will be sourced from tables 2-1 and 2-2 of Engineering Recommendation P2/6. These will be applied to all HV/LV generation irrespective of P2/6 thresholds.

1.56. The P2/6 security factor (F-Factor) will be multiplied by the calculated yardstick from the DRM and multiplied by -1 to provide a negative charge. The negative charge reflects the positive impact generation has on the network at this level.

1.57. Generator charges will be calculated using the following formula:

$$GDUoS = DRMYardstick * FFactor * (-1)$$

F factors need to be specified in the charging methodology for each technology, along with detail provided on how F factors apply at LV.

Format of Charges

The detail of tariff structures is to be developed by DNOs.

Scaling

1.58. In order to match HV/LV generator charges to allowed revenue, the yardsticks will be subject to scaling. A fixed adder method will be applied to HV/LV generator charges as per all other charges in the DRM model.

Detail of scaling to be developed by DNOs: fixed adder approach, further detail to be worked up. Note the interactions with the price control review and associated special licence conditions.

4. IDNO charging

IDNO charging is to be developed by DNOs working with IDNOs.

Appendix 3 – Consultants' terms of reference

Requirement for consultants

1.1. Consultants will provide an independent view and a way of ensuring timely collective development of the charging methodologies. The project requires an intensive period of work to determine and deliver detailed spreadsheets and collating and discussing DNOs’ views on the detail. Technical expertise and experience of charging methodologies is required to achieve this.

1.2. The following sections describe Ofgem's views on the terms of reference for consultants.

Overall objectives

1.3. The overall objectives of this consultancy work are to:

Phase 1

- Establish a suite of charging templates that will be used by DNOs to calculate use of system charges; and
- Report on DNOs’ thinking on the course of action for the items marked for future development including interactions with price control licence conditions.

Potential phase 2

- Work with DNOs to deliver populated charging templates; and
- Work with DNOs to conclude policy on issues for future development and help DNOs implement solutions in these areas.

Key work areas

Phase 1

- Work with DNOs to deliver spreadsheets to capture the requirements of the common methodology in discussion with DNOs.
- The spreadsheets should either include enough description / detail to enable DNOs to understand the inputs required or a user manual should be developed giving this detail; and
- Provide a report to DNOs and Ofgem commenting on the spreadsheets.

Potential phase 2

- Work with DNOs to deliver populated charging templates, logging issues and matters which require changes to the template;
- Work with DNOs and Ofgem to raise issues arising from implementation of the common methodology; and
- Report to Ofgem on the implementation phase of the project.

Approach

1.4. Consultants will need to consider our decision on the principles and assumptions for use of system charging and develop detailed spreadsheets to allow for the calculation of charges. The consultants will be required to meet with DNOs both bilaterally and at working group meetings which will be attended by Ofgem. In addition, the consultants will need to report directly to Ofgem on progress every week with progress meetings approximately every fortnight.

Key deliverables and indicative timetable

Phase 1

1.5. The key deliverable from this work will be a suite of charging spreadsheets for DNOs to fill in plus a report to Ofgem to be completed by 19 December 2008. The spreadsheets must set out all inputs and calculations to enable DNOs to calculate use of system charges for demand and generation customers across their EHV, HV and LV networks.

1.6. This report will provide a structured, detailed review of the work carried out by the consultants. It should comment on the spreadsheets, detailing:

- Areas / inputs that were discussed and decided by DNOs
- Areas of contention
- Any additional areas highlighted for future development
- Any additional issues noted in developing the spreadsheets

Potential phase 2

1.7. The key deliverable will be for the consultants to work with DNOs to ensure delivery of completed spreadsheets by each DNO along with illustrative prices. Consultants will be required to keep a log of implementation issues to Ofgem and to report on the implementation phase of the project.

Milestones – Phase 1	Timing (2008)
Draft report and suite of spreadsheets to DNOs and Ofgem	16 December
Final report and suite of spreadsheets	19 December
Milestones – Potential phase 2	**Timing (2009)**
Regular meetings with Ofgem on progress	January-August
Final report on implementation phase of project	20 August

Further detail

Progress Meetings

1.8. Progress updates should be submitted to Ofgem on a weekly basis or as agreed from time to time. Progress meetings should be held with Ofgem every fortnight, or as otherwise agreed.

Experience

1.9. The successful consultants will need knowledge and experience in the following areas:

- Knowledge and understanding of the electricity distribution use of system charging structure of charges project;
- Knowledge and understanding of DNOs' charging models, including the DRM and LRIC
- Project management experience; and
- Knowledge and understanding of price control interactions.

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.[32]

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[33].

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 consumers, present and future, 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[34]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[35]

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:

[32] entitled "Gas Supply" and "Electricity Supply" respectively.
[33] 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.
[34] 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.
[35] The Authority may have regard to other descriptions of consumers.

- Promote efficiency and economy on the part of those licensed[36] 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;
- Contribute to the achievement of sustainable development; 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[37] 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.

[36] or persons authorised by exemptions to carry on any activity.
[37] 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.

B

BERR

Department for Business, Enterprise and Regulatory Reform (BERR): UK Government department responsible for business, enterprise and regulatory reform. The department was created in 2007.

C

Competition Act 1998

The Competition Act 1998 (CA98) gives the Office of Fair Trading and the sector regulators, powers to apply and enforce Articles 81 and 82 of the EC Treaty as well as the Chapter I and II prohibitions of CA98 using their concurrent powers. Article 81 and the Chapter I prohibition prohibit agreements which have the object or effect of preventing, restricting or distorting competition. Article 82 and the Chapter II prohibition prohibit conduct by one or more undertakings which amounts to the abuse of a dominant position in the market.

D

Distributed Energy / Distributed Generation

Any generation which is connected directly into the local distribution network, as opposed to the transmissions 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 transported for use across the UK.

DNOs - Distribution Network Operators

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

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 will expire 31 March 2010. DPCR5 will be the fifth review of the price control and is expected to commence in early 2008. The resulting price control is planned to commence 1 April 2010.

DSA – Distribution services area

As defined in SLC 1 of the electricity distribution licence.

DCUSA
The Distribution Connection and Use of System Agreement (DCUSA) is a multi-party contract between the DNOs, suppliers and generators of Great Britain. It is concerned with the use of the electricity distribution systems to transport electricity to or from connections to them.

E

The Electricity Council
The Electricity Council was a governmental body set up in 1957 to oversee the United Kingdom's electricity supply industry. The Council was formally wound up by The Electricity Council (Dissolution) Order 2001.

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

Extra High Voltage (EHV)
Term used to describe the parts of distribution networks that are extra high voltage.

H

High Voltage (HV)
Term used to describe the parts of distribution networks that are high voltage.

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 the UK.

L

Lower Voltage (LV)
Term used to describe the parts of distribution networks that are lower voltage.

M

Microgeneration
The term microgeneration is used to refer to electricity generation equipment of the smallest capacity which covers generation of electricity up to 50 kWe.

P

Engineering Recommendation P2/6
A guide for electricity distribution network system planning and security of supply. It is a revision of Engineering Recommendation P2/5 issued in 1978, which it supersedes.

S

SLC - Standard Licence Condition
These are conditions that licensees must comply with as part of their licences. SLCs can only be 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.

U

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:

- Does the report adequately reflect your views? If not, why not?
- Does the report offer a clear explanation as to why not all the views offered had been taken forward?
- Did the report offer a clear explanation and the reasons for the decision? If not, how could this information have been better presented?
- Do you have any comments about the overall tone and content of the report?
- Was the report easy to read and understand, could it have been better written?
- Please add any further comments?

1.2. Please send your comments to:

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