Structure of electricity distribution charges

Consultation on the longer term charging framework

May 2005

Summary

The structure of charges project has been developed in two stages. Interim charging arrangements took effect on 1 April 2005, and development of enduring and longer term arrangements has recently begun in earnest. It is expected that developments and improvements to the interim regime will be implemented between 2005 and 2010.

With the interim charging arrangements now in place, the aim of this document is to set out Ofgem's initial thoughts on the development of longer term charging arrangements for electricity distribution networks, and explain what work has been carried out by Ofgem, the industry and three groups of academics in recent months. The document outlines and discusses the various options for distribution charge setting models, and also notes some of the issues associated with the development of use of system charges for demand and generation.

Ofgem expects to publish conclusions on these topics in the summer, with the intention of providing a platform for development of longer term and enduring charging arrangements by the DNOs and the industry.

Following the introduction of the new charging methodologies and the associated methodology modification process on 1 April 2005, Ofgem expects that the development of the longer term arrangements will be predominantly led by the DNOs and industry in accordance with the methodology modification process, but will continue to be supported by the Ofgem led review during 2005.

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1. Introduction

1.1. Ofgem and the industry began work on the development of longer term charging arrangements at the beginning of 2005, following completion of the implementation work associated with the interim charging regime and the introduction of charging methodologies for connection to and use of the distribution system.

1.2. This document provides details on the form this work has taken, and seeks industry views on the various charging options. Ofgem will build on responses to this document to formulate conclusions on the key charging issues, to be published in the summer. These principles will then form the basis of the Distribution Network Operators' (DNOs) work on the long term charging arrangements from 2005 onwards.

1.3. Currently, the timetable for 2005 is as follows:

9 May	Consultation published
24 May	Public workshop on charging issues
20 June	Responses due
Summer	Ofgem decisions on high level framework announced
Summer/autumn	DNO modification proposals
Autumn	Implementation discussions

1.4. This timetable is discussed in more detail in chapter 6.

Structure of this document

1.5. The structure of this document is as follows:

Chapter 2 Background

Chapter 2 sets out the current status of the Structure of Charges (SoC) project, and the regulatory framework and rationale for the charging methodologies.

Chapter 3 Use of System charging models

This chapter describes the issues and possible solutions for long term use of system (UoS) charging models, covering a review of the existing charging models employed by the DNOs, the conclusions of the academics recently engaged by Ofgem to consider UoS models, the views of the SoC Implementation steering group (ISG) and some provisional Ofgem views.

Chapter 4 Detailed charging issues

This chapter describes some of the key charging issues which must be considered, but which are separate from the charge setting models, again incorporating academic, ISG and Ofgem views where relevant.

Chapter 5 Impact Assessment

Ofgem is not proposing to issue a formal impact assessment. This chapter sets out the reasoning behind this decision, and seeks views on associated issues.

Chapter 6 Ofgem and industry involvement – 2005 onwards

This chapter discusses the timetable for 2005 and Ofgem's view of how this project should be led in the future.

Responding to this document

1.6. Ofgem welcomes responses and comments to the issues raised in this document from interested parties, including DNOs, suppliers, distributed generators, customers and their representatives. Views are invited by Monday 20 June 2005. Where possible, responses should be sent electronically to:

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1.7. All responses will be held electronically in Ofgem's Research and Information Centre. They will normally be published on the Ofgem website unless they are clearly marked confidential. Consultees should put confidential material in appendices to their responses where possible. Ofgem prefers to receive responses electronically so that they can easily be placed on the website.

1.8. Copies of this document and other material relating to this project are available on the Ofgem website under the Electricity Distribution Charges area of work.

1.9. Should you have any questions regarding the issues raised in this document please contact Mark Cox on 0207 901 7458.

2. Background

2.1. The structure of electricity distribution charges has not changed significantly since the 1980s. In December 2000, Ofgem launched a review of whether the existing structure remained appropriate. The review was driven by concerns over the divergence of charging arrangements between different distribution companies and the recognition that the current arrangements needed developing given the expected increase in distributed generation (DG). In October 2002, Ofgem published an update document that set out three key aims:

- to review the charging principles established by the Electricity Council during the early 1980s;
- to establish what proportion of network costs should be recovered through up-front charges for connection and ongoing charges for use of the distribution system (the connection boundary); and
- to establish the framework for distributed generator use of system (GDUoS) charges for implementation from April 2005.

2.2. An initial decision document was published in November 2003[1] proposing that by April 2005 the clearest problems with the current structure would be addressed through interim arrangements, while work would continue in parallel on the development of a longer term solution.

2.3. The April 2004 document[2] provided an update on policy areas associated with the interim charging arrangements. The April 2004 document also contained details of the collective licence modification to standard licence condition (SLC) 4 required to implement the new methodologies. Following some amendments, the Authority gave notice of the intended changes to the licence on 1 June 2004[3]

[1] 'Structure of electricity distribution charges: Initial decision' Reference 142/03, available from http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges
[2] 'Structure of electricity distribution charges: Update and licence modifications' Reference 76/04, available from http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges
[3] Section 11A notices, Reference 121/04 and 150/04, available from http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/licensingmodifications

and the changes took effect from 7 July. The licence modification was also required to comply with Article 23 of EC Directive 2003/54.

Charging methodology development and conditional approvals

2.4. DNOs submitted draft UoS and connection charging methodologies in September 2004. Ofgem consulted the industry on the form and content of these documents in October 2004[4]. DNOs then submitted revised charging methodology statements to the Authority at the end of November 2004 and then following discussions with Ofgem, the Authority approved final charging methodologies to take effect from 1 April 2005[5] in February 2005. These approvals concluded the introduction of the interim charging arrangements, covering:

- a common connection charging boundary for demand and generation;
- the removal of deep connection charges and the introduction of use of system charges for new generators; and
- a requirement for DNOs to publish their charging methodologies and justify their approach to setting tariffs in accordance with the licence objectives.

2.5. Some of the UoS charging methodologies were approved subject to conditions, which were imposed by the Authority to ensure that the charging methodologies achieved the relevant licence objectives (SLC4(3) and 4B(3)). The conditions (which are set out and explained in the February 2005 decision documents) require the DNOs to undertake certain actions by specified dates, and changes to the methodology to satisfy the conditions will need to be submitted to the

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[4] 'Structure of electricity distribution charges: proposed DNO charging methodology statements' reference 235/04, available from http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges

[5] 'Authority approval of DNO charging methodologies' document references 36-42/05, available from http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges. Note that the final charging methodologies are not published on the Ofgem websites – these can be found on the DNO

Authority for approval in advance of each condition's deadlines[6]. Ofgem will monitor the DNOs' progress in meeting the outstanding conditions, and the Authority will consider enforcement action as necessary where the conditions are not met.

2.6. The longer term framework will be facilitated through changes to the methodologies proposed by the DNOs and approved by the Authority. The procedure for this is discussed in more detail in chapter 6.

Longer term arrangements

2.7. Ofgem's November 2003 document[7] stated that use of system charges for demand and generation regimes should be fully aligned with UoS charges established via charging models based on forward looking long run incremental cost (LRIC). It is also considered different options in the approach to take.

2.8. Further consideration has been given to this since then, particularly in the last few months, and this document consults on the key issues arising from this work. Ofgem expects to issue a decision document on the high level framework in the summer. Further thoughts on the timetable for the longer term framework going forward are set out in chapter 6.

websites.
[6] The connections methodologies are now all approved without conditions. Updates on the relevant DNOs' progress in meeting the outstanding UoS conditions, and Authority decisions on subsequent modifications, will be published on the Ofgem website under the Electricity Distribution Charges section.
[7] 'Structure of Electricity Distribution Charges: Initial decision', reference 142/03, available from the Ofgem website at http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges

3. Use of system charging models

Charge setting process

3.1. DNOs' overall revenues are determined by their price controls. Allowed revenues take into account forecast capital and operational spending, growth in customer numbers and units distributed and the need to incentivise the DNOs to run an efficient network and improve their performance (through various incentive schemes). Allowed revenues represent the total amount which can be recovered from customers in any one year.

3.2. Distribution use of system (DUoS) charges are set by each DNO based on their assessment of system costs, fed into a charging model to determine the cost of additional load at each level of the distribution system and an appropriate cost recovery split between customer groups. The models assess reinforcement costs, and exclude costs which are recovered from the customer in full (connection charges or transactional charges). The 500MW distribution reinforcement model (DRM) has been in widespread use since the 1980s. The DRM (and some issues concerning its use) is described in greater detail below.

3.3. The output of the charging model is theoretically cost reflective charges for each customer or group of customers. Under current practice, these charges are then scaled equally so that the DNO recovers its allowed revenue.

3.4. The output of the charging model is also subject to each DNO's decisions on tariff design, and its assessment of the appropriate split between different charge elements (fixed and unit charges). Contractual considerations also have an effect, as DNOs and customers can negotiate fixed price long term contracts.

Move from interim to longer term arrangements

3.5. The DNOs' charging methodology statements were approved in February 2005. These describe the current charge setting process, and put in place the interim charging arrangements agreed by Ofgem and the industry for 1 April 2005.

3.6. As of 1 April 2005, the DNOs' methodologies must conform to the objectives set out in SLC4(3) and 4B(3). These state that methodologies should:

- facilitate the discharge of the DNO's obligations under the Act and its licence;
- facilitate competition in supply and generation, and not restrict competition in transmission or distribution;
- be cost reflective, as far as is practicable once implementation costs are taken account of; and
- take into account developments in the licensee's distribution business.

3.7. The current methodologies have been approved as a baseline, and in accordance with the two stage implementation of the conclusions of the structure of charges review, Ofgem expects that the methodologies will now develop in order to deliver a longer term charging framework that better meets the licence objectives.

3.8. Central to this development will be the creation of new charging models which accurately reflect forward looking costs, incentivise efficient usage and development of the system, and accommodate the introduction of generator use of system charges (GDUoS) better than the current models.

3.9. The issues concerning treatment of the outputs of the models (scaling, tariff structures etc) will still remain, even with more sophisticated models in place. Consideration of how these issues should be treated is set out in chapter 4.

Options for new charging models

3.10. This chapter considers the appropriateness of the current charging model (the DRM) and considers the options for different charging models.

3.11. Chapter 3 also considers how the DNOs will work towards development of these new models. These include consideration of whether further work is required by the DNOs to identify key drivers of investment costs on the system to inform decisions on the selection and design of use of system charging models, and the question of whether there are benefits to collaborative working by the DNOs on this project.

3.12. Ofgem has also been mindful of the need to gather a wide range of views in the first stages of development of longer term charging arrangements. Chapter 3 includes, where appropriate, the views of those who have been involved in this development process so far, including:

- Views and conclusions from the SoC ISG[8];
- Provisional views from Ofgem; and
- Views from Ofgem-commissioned academic reports: in January 2005 Ofgem engaged three academics to consider the longer term charging framework for electricity distribution. These were David Newbery (et al[9]), Goran Strbac (et al[10]) and Ralph Turvey[11].

Charging principles

3.13. As a first step in the process of determining an appropriate framework for long term distribution charging, Ofgem and the ISG considered appropriate high level charging principles (to sit alongside the licence objectives). The group concluded that these were:

- Cost reflectivity;
- Simplicity;
- Transparency;
- Predictability; and
- Facilitation of competition.

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[8] The ISG was established for the industry and Ofgem to discuss charging matters. It consists of DNO, IDNO, supplier, customer and generator representatives. Views expressed here based on discussions at the ISG do not necessarily reflect the opinions of all attendees or their organisations.
[9] David Newbery, Karsten Neuhoff, Michael Pollitt and Tooraj Jamasb of Cambridge University
[10] Goran Strbac and Joseph Mutale
[11] Frontier Economics. All three of the academics' reports, together with the original scope of work, were published on the Ofgem website (Electricity Distribution Charges section) on 24 March 2005. Those reports are referred to in this document, but specific page numbers are not included for each reference.

3.14. The ISG has recognised that there are practical constraints which create the potential for conflict between some of these principles. For example, while cost reflectivity is a licence objective, this needs to be balanced by evidence of benefits of introducing more complex charging structures. The principles also interact, for example transparency and predictability may facilitate competition.

3.15. Ofgem notes that charges need to reflect considerations of economic efficiency whilst ensuring DNOs recover their allowed revenue, provide clear pricing signals to customers and avoid undue uncertainty.

3.16. Economic efficiency would suggest that charges should ensure that those who value capacity most get it. This would suggest a need for transparent pricing signals with prices determined on the basis of key cost drivers. For example, if peak demand was determined to be a key driver of costs it would be appropriate to charge in a manner that would allocate capacity at times of peak demand on the system. Efficiency would also suggest that access to the system should also be determined in an equitable manner.

3.17. Efficiency means that consideration should also be given to ensuring lowest cost provision of the system which would include the requirement for the provision of efficient investment signals to customers such that future network needs are met efficiently. Past costs are the result of decisions already taken and hence cannot be affected by future charges. Only future decisions can now be influenced and hence the key driver for economic efficiency is to reflect future costs.

3.18. However, long term decisions will be based on expectations of future costs, rather than solely on current charges, so it is important that future charges are predictable, as far as possible, and that reasonable expectations are not overturned without good reason. Setting charges to reflect future costs will help minimise these costs, as far as this is efficient. Such cost reductions will benefit both DNOs (increasing their profits under the price control) and network users (charges will be lower in due course).

3.19. Academic views on key features of a charging model are set out below, which relate to these key principles.

Current charging model

3.20. DUoS charges are generally based on the 500MW DRM, although it is noted that not all DNOs use this model. The DRM has been used to calculate charges by DNOs since the 1980s[12].

3.21. This model contains assets at modern equivalent prices (current costs) which are based on a scaled representation of the DNO's whole system or how they would plan their system, or a simulated system. Yardsticks (£/kW) are calculated from the DRM for each voltage level.

3.22. The DRM model measures the costs of an additional 500MW capacity at the time of peak demand and averages this cost across users at each voltage level. Therefore, the DRM represents most closely an average cost for customers at given voltage levels at peak demand within the marginal 500MW increment.

3.23. The model is used to determine yardstick costs by customer class. The contribution of a customer group to peak demand (the coincidence) is the method by which costs are divided between groups, taking in to account diversity factors and load profile. This method is used because consumption for non half hourly (NHH) metered customers is not measurable at times of peak. Coincidence factors based on load research therefore form the basis for different tariffs to take account of different usage at peak.

3.24. The model is considered deficient in its inability to accommodate GDUoS charges because the DRM is voltage based and does not take account of locational factors. It was set up to take account of the cost required to meet incremental demand (500MW simultaneous maximum demand) assuming that

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[12] CE Electric UK (NEDL and YEDL) and Central Networks (CN East and West) have moved to a model based on reflecting regulatory revenue which is to some extent 'founded' on DRM output charges but these models are significantly different to the other DUoS tariff setting models. Charges at EHV are generally site specific and represent the annuitised cost of assets required for connection, plus maintenance, that have not already been paid for in upfront connection charges.

power flows from grid supply points at high voltage to customers at lower voltage levels. Charges are allocated between customer classes based on their contribution to system peak demand: generators do not feature in such calculations and the model fails to recognise that peak generation loading may not occur at times of maximum demand and that coincidence of peak at different points in the system may not occur at times of system peak. For example, the DRM would not take account of the cost implications of reverse power flows caused by net generation.

3.25. Turvey notes that it cannot deal with downward cost messages, i.e. costs saved by ceasing to serve existing customers (other than by assuming that it equals an upward cost movement with a change of sign) or adequately with demand diversity or generation connections.

3.26. As well as noting the DRM's inability to produce generation charges, Newbery's report notes that the model cannot deal with locational issues and that the model underestimates the marginal cost of load and the benefits of connecting distributed generation.

3.27. In addition to these points, Strbac notes that the DRM does not deal with temporal variation or the impact of multidirectional flows on the system.

3.28. Some DNOs have commented at ISG meetings that the current charging model could be maintained, and a separate regulatory approach taken for generation over the long term. Ofgem considers that it is important to reflect costs imposed on and benefits provided through assessing the impact of demand and generation on costs in the same framework.

3.29. Ofgem considers it possible that distribution systems have changed since the introduction of the DRM in terms of factors such as constraints, utilisation factors, and power factors. In order to be cost reflective and to incentivise economic efficiency, a charging model needs to take account of these changes. Hence the costs/benefits of timing and generation (e.g. reverse power flows) need to be taken in to account in charging messages, where possible on a locational basis (see below). Ofgem also considers that while charges at different voltage levels may differ (for example, LV charges being averaged and EHV charges site specific) it is most robust to use one approach to determine charges at all levels and for demand and generation, to ensure non discrimination. The outputs from such a model could then be tailored to different voltage levels as necessary to allow practical implementation of the model.

3.30. In considering the need for change, Ofgem views that it is especially important to ensure charges at higher voltages are cost reflective. Half hourly (HH) metered customers can account for up to half the units distributed in some DNO areas even though they constitute a tiny (less than 0.5%) proportion of total customer numbers, but the DNO can more readily affect their behaviour through pricing signals than those on NHH meters.

3.31. This issue of the applicability of any charging model to generation and demand is considered below.

Type of model

3.32. Ofgem's November 2003 consultation document[13] considered four LRIC models: entry-exit, generator and demand UoS charges and a contract path model plus an option to split the regulatory asset base between generation and demand. Respondents to these proposals preferred the first two options.

3.33. Ofgem asked the groups of academics what type of model they would advocate and what key features would be. The ISG has discussed the academic reports. Key issues and associated views dealing with UoS charging models are captured below.

Incremental cost

3.34. As set out above, economic efficiency determines that charges should be levied in line with what drives network costs.

[13] 'Structure of electricity distribution charges: Initial decision' reference 142/03, available from http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/distributioncharges.

3.35. The academics agree that the efficient charge is the long run cost on a forward looking basis since charges should influence future behaviour and investment decisions in terms of the size and location of loads.

3.36. Similarly, the academics state that the costs should be calculated on the basis of costs brought forward, delayed or avoided by changing decisions over the timing of network development and asset replacement, costs which Turvey describes as 'net present worth'. Turvey sets out that costs are valued over the time period of the advancement or postponement in cost.

3.37. Turvey and Newbery distinguish between the short and long run costs, setting out that long run cost messages should influence investment and siting decisions: short run costs should be designed to affect capacity usage once installed. Tariffs ought to therefore convey a long run message even though supply contracts are short term.

3.38. Turvey sets out the importance of the avoidable costs of larger increments as opposed to marginal increments and believes that the concept of pure marginal cost is irrelevant because of indivisibilities in plant size. He believes that marginal cost comes in to assessments over the timing of reinforcement and extension works rather than whether to undertake the works, a decision that is concerned with total cost recovery.

3.39. Newbery makes a similar point, noting the potential difficulty of assessing and apportioning costs where asset sizes are indivisible. This issue has been reflected in connection charges for the interim solution through the development of the apportionment rules, but this needs to be considered further for the longer term and during development of new models.

3.40. The academic reports also highlight that costing may be difficult in the assessment of different project options where there is a choice between investing in active system management or maintaining passive management.

3.41. The academics commented on the applicability of marginal costing to the whole distribution system:

- Newbery notes that marginal cost charging is more important for large loads and distributed generation with a meter as these parties can respond to charging signals whereas small loads are likely to be less responsive to pricing signals.

- Turvey believes that cost signals should be fully passed on to suppliers who can then determine the appropriate charge to customers, although he notes that the current system of profiling NHH customers currently inhibits this.

- Strbac thinks marginal pricing is appropriate across the whole DNO network in principle.

3.42. Ofgem believes that an economic model to encourage efficient network development could be implemented which would reflect the long run incremental costs associated with the connection of additional incremental capacity at a given point in time.

3.43. Ofgem recognises that any model for estimating marginal costs may be subject to certain assumptions. Turvey advocates scenario-based studies at each location on the distribution system. Implementation of such a regime could prove to be complex and resource intensive, however, and hence a model based approach may be more practical to implement.

Forward looking costs

3.44. The majority of ISG members agree that the focus in tariff setting should be on reflecting future costs, in the interest of both increasing system efficiency and decreasing DNO costs. It was agreed that this would include both the asset cost, e.g. through modern equivalent asset prices, and also setting prices considering a forward looking view of the development of the network. Some members of the ISG questioned the impact of forward looking costs on existing parties.

3.45. Planning horizons were considered by the group, and it was noted that DNOs are currently required to produce a SLC25 long term development statement, which has a five year horizon. The ISG has also considered National Grid's

(NGC) approach, which uses year-ahead data as the basis of the model[14]. Given the nature of the DNOs' projects, the group concluded that planning horizons on distribution networks would not be any longer than those used by NGC. The DNOs cautioned that reflecting future costs will always involve some level of estimation, but agreed that there are ways in which to improve the accuracy of forecasts.

3.46. For the distribution companies the NGC approach may provide a useful benchmark. It would appear appropriate that DNOs look ahead only as far as they can make effective forecasts, but it was also noted that the lumpiness of investment could make longer term planning preferable, especially in the interests of predicting any step changes in investment and signalling these in locational prices. The ISG agreed that one to five years would appear appropriate and would need to be kept under review by the DNO over time.

3.47. Ofgem notes that there are different methods of modelling with forward looking planning and investment. For example, a model could be static which would mean taking a snapshot of a given scenario (e.g. one year ahead). Alternatively it could be a dynamic, time-based model which would consider a series of planning and investment scenarios over different points in time.

Cost drivers

3.48. As set out above, efficiency determines that charges should be levied in line with what drives network costs.

3.49. Discussions in the ISG supported the view that capacity is the key driver of costs on the distribution system whilst noting that other factors (such as fault levels) may influence costs. In terms of other networks, this assessment is in line with NGC's recent study of investment on the transmission system (see below) which concluded that capacity at peak is the main driver of investment. In addition to NGC's study, Transco carried out a detailed analysis of cost drivers on the gas

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[14] Whilst assessing the design of the investment cost related pricing (ICRP) model in 1992, NGC recognised that using data more than one year in advance would cause issues due to uncertainty.

distribution network (DN) in 1999[15] and concluded that about 99% of DN incremental costs are capacity related.

3.50. The academics draw out various investment cost drivers. Strbac notes that investments are determined by network design standards as well as regulatory incentives concerning quality of supply, losses and incentives to connect distributed generation. In particular, he notes the following:

- security standards;
- system fault levels;
- network losses; and
- service quality expenditure.

3.51. Losses were highlighted as a cost driver in Strbac and Newbery's reports. Strbac notes that losses may drive investment in lines and cables due to the trade off between capital costs and the cost of losses on the system. He suggests that marginal losses be calculated (on both the distribution and transmission systems) taking account of active and reactive power.

3.52. Losses were discussed by the ISG but there was not a strong view that they are currently a significant cost driver of investment. It was noted that losses are already factored in to decisions concerning capital expenditure and scheme design. The group noted that the losses incentive means that DNOs are not exposed to the purchase price of losses themselves but are incentivised to minimise network losses. Some ISG members suggested that there was a possibility that the incentive could act as a cost driver.

3.53. Strbac notes that fault levels can cause costs for generator connections and that the costs associated with this could be captured in prices, since network design studies will tend to include analysis of fault levels. Ofgem understands from the industry that the impact of connecting parties on fault levels on the distribution

[15] 'Capacity/Commodity Split, Transco Pricing Discussion Paper PD4', 1999, p.4, available from www.transco.co.uk. This analysis was based on an incremental cost study in which Transco identified a range of costs that would have to be incurred in order to meet a 10% increase in demand.

system may be a more significant issue than for the transmission system and may need to be catered for within the charging arrangements.

3.54. Ofgem considers that cost drivers are fundamental to the determination of suitable charging models. Further work is required by the DNOs to determine and demonstrate key cost drivers and associated issues, such that the DNOs' work on development of charging models can be informed by accurate information on these cost drivers and the most appropriate models produced to accommodate them. This work should consider whether a charging model needs to reflect time of day and seasonal influences[16]. This information can then be used to determine the type and structure of tariffs required and to assess trade offs between cost reflectivity, simplicity, transparency and implementation costs.

3.55. In addition, Ofgem notes that in order for distribution charges to be fully cost reflective, it needs to be clear how costs are calculated and the level of costs that are being assumed (e.g. whether costs are associated with N-2, N-1 or N-0 levels of security and what planning standards are being assumed). Consideration needs to be given to the definition of a secure network and whether there is a requirement for a connection security standard for generators.

Applicability of any model to demand and generation

3.56. In developing the long term charging framework a decision needs to be made concerning the symmetry of treatment between demand and generation in any charging model. This decision cannot be made before detailed work has been carried out by the DNOs to demonstrate what drives investment costs on each network.

3.57. Strbac considers that such symmetry within the charging model is appropriate although he notes that security requirements may differ between demand and generation and a model may have to treat outputs differently.

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[16] At transmission level NGC levies use of system charges (TNUoS) predominantly based on winter peak triad demand.

3.58. Newbery believes that symmetry is appropriate in considering costs imposed on the network, but advocates adjusting estimates of cost in different ways in the mark-up to allowed revenue to account for differences between generation and demand. This issue is considered further in chapter 4.

3.59. Turvey sets out that demand and generation should not necessarily be treated in the same manner because the impact of locational charging is thought to have a greater influence on generation than demand, and cost drivers may differ.

3.60. Ofgem believes that symmetry between demand and generation charges in a model may be appropriate for capacity, but other cost drivers such as fault levels would not be symmetric.

3.61. If fault levels are determined to be a first order driver of cost it will be necessary to determine methods of identifying and then charging for such costs. This could result either in directly attributing costs to parties and charging these as a one off cost to the triggering party (either as an up-front charge or annuitised over a number of years[17]). Another possibility is to identify the forward looking cost of fault levels and charge this via a separate tariff element for generators.

3.62. Ofgem recognises that further work by the DNOs on cost drivers is required to determine key cost drivers. Views on this matter within consultation responses are welcomed.

Locational variation

3.63. Each of the academic reports recognises the importance of reflecting locational influences in a charging model.

3.64. Turvey advocates the assessment of costs on a site specific basis as far as possible, to take account of location. Strbac's model takes account of locational variation at high voltages based on the actual network, and variation on medium and low voltages based on a simplified network.

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[17] An annuity would require security arrangements to be in place to ensure full cost recovery.

3.65. Newbery considers that locational charges may be important for generators but suggests that location will not influence demand decisions.

3.66. Ofgem believes that locational signals could promote efficient investment signals to both new and existing connectees planning developments such as demand customers considering new on-site generation.

3.67. Ofgem recognises that there are various means of determining locational charges, for example, access auctions are carried out for capacity on the gas transmission system (NTS), subject to a reserve price. These auctions allow capacity to be reserved for up to 13 years.

3.68. Ofgem notes that any introduction of locational charges on a nodal basis could result in hundreds of tariffs which might have implications for the interface between DNOs and suppliers in terms of billing system capabilities. Zonal charges are an alternative to nodal charging and may lead to more stable cost messages, although any rezoning would affect this stability. A zonal approach to charging is adopted by NGC. Given the radial nature of much of the distribution system (as compared to the transmission system) there is a higher likelihood that individual parties may have a greater impact on the system and cause charges to fluctuate at a particular node. For example, the addition of a generator may cause use of system charges to change sign.

3.69. Ofgem believes that charging on a more locational basis would be beneficial. However, the likely response of customers to locational pricing signals is currently unclear, and if this system was adopted, it would be necessary to consider the elasticity of response to changes in pricing signals to inform decisions over the optimum number of locational signals and tariffs. For example, if such analysis showed that fully nodal charges would help promote competition at EHV and HV levels then there would be a benefit in allowing multiple tariffs at these voltage levels.

System load flow models

3.70. Of the academics, Strbac specifically advocates the use of a load flow model in determining who should pay for use of system at a particular node. This model is described below.

3.71. The ISG has considered NGC's DC load flow (DCLF) model, taking into account the differences between the distribution and transmission systems and the behaviour of customers on each. It was concluded that, albeit with some assumptions for the low voltage network, the DCLF could be applied to distribution networks.

3.72. One DNO suggested that in terms of numbers of bulk supply points and primary substations (i.e. the EHV network only), one DNO network was roughly comparable in size to the transmission network, therefore such a model might be applied. The group raised an issue over capacities of connection on the two systems, suggesting that at transmission level the size of connections (predominantly generation) tended to correspond to the size of assets more closely. At distribution, the group considered that connections were less likely to match asset sizes, and thus the application of the DCLF might prove more difficult.

3.73. The group also considered the application of an AC load flow (ACLF) model for distribution: while the group thought this was possible, they also questioned whether it would create unnecessary complexity. However, it was noted that an ACLF model could be used on distribution systems because existing system studies tend to be carried out on an AC basis.

3.74. Ofgem considers that, insofar as costs are determined by capacity requirements, load flows could be used to determine estimates of forward looking cost.

Specific models advocated by the academics

University of Manchester model

3.75. United Utilities (UU) has been working with the University of Manchester to develop a new UoS charging model. Strbac sets out the model in his report. The model is based on load flows and the assessment of whether current passing between two nodes is demand dominated, generation dominated or balanced.

3.76. The model apportions costs between demand and generation users and between different users at different voltages and is based on a reference network which has the same topology as the real system.

3.77. Entry-exit pricing models are constructed. Each item of plant (transformer, cables, and overhead lines) on the generic network is determined as being either generator or demand dominated or roughly balanced. This is established by examining load flows at the point of maximum load (critical flow) on the plant which is either the point of minimum demand coinciding with maximum generation or maximum demand coinciding with minimum generation.

3.78. Where the direction of the critical flow coincides with the flow imposed by a particular network user the user will be charged for use of the plant. Conversely, where the direction of the critical flow is opposite to the flow created by a particular user, the user will get paid for the use of the plant.

3.79. Annuitised capacity costs (£/kW/year) are allocated to network assets in order to calculate the DUoS charges for a user. A demand customer will pay for the use of all upstream assets that are demand dominated and will be rewarded for the use of all upstream assets that are generation dominated.

3.80. Turvey states that the University of Manchester model may not be correct in treating generation and demand in the same manner because DG may not encounter the same cost drivers as load because each may impact differently on the network: the University of Manchester model assumes that thermal constraints determine the need for capacity in all cases. In addition, Turvey notes that the proposed University of Manchester model does not take account of indivisible plant (nor does the DRM model). Plant indivisibility means that new capacity may not be fully utilised.

3.81. Turvey suggests that a University of Manchester-type model could be applied at EHV down to 33/11 kV level, saying that modelling below this level would be impossible due to computational difficulties associated with such an extensive distribution system.

3.82. Ofgem views the University of Manchester model as a good illustration of what can practically be achieved in terms of an alternative approach to the existing charging model. The model appears to be flexible in its ability to cope with different assumptions and could be developed over time.

Newbery model

3.83. This report suggests that charging messages should be consistent across transmission and distribution for generators and sets out a UoS charging model that is location-specific. The model considers long run incremental costs in terms of the impact of timing on voltage and thermal constraints, the impact of connections on losses and the impact of connections on future schemes to reduce losses. Similarly, a locational connection charge is favoured.

3.84. A charging model is advocated along with certain characteristics that it should incorporate: an asset register, the current network, the ability to consider asset requirements to meet future demands, to determine least-cost expansion, to calculate losses and deal with ancillary services. The report also recommends that it should be available and understandable to external users.

Turvey model

3.85. Turvey advocates the use of engineers to estimate the costs of installing and maintaining the network. He suggests that use of system charges be based on thermal capacity, voltage, fault levels and stability, although thermal considerations could be used if this were determined to be sufficiently cost reflective.

3.86. Overall, a model based on location-specific connection charges is preferred to a use of system charging model for the recovery of investment costs, unless a use of system charging model can be demonstrated to be sufficiently cost reflective. Turvey's report notes that these charges could be levied either up front or as an annuity and suggests connection charges for all but smaller DG, including for shared assets. Connection charges are preferred as they can take in to account individual cases and can consider relevant cost drivers individually.

3.87. Turvey states that further information is required to assess the appropriate mix between connection and use of system charges and recognises that use of system charges would be required in any case to ensure the recovery of allowed revenue.

3.88. Ofgem notes that Turvey's proposals for charges to be determined on a case by case basis would require various assumptions to be made which may lead to inconsistent decision making and the risk of dispute. In addition, the Electricity Act states that charges for connection are levied in relation to the assets provided, and Turvey's notion of costing in terms of 'present worth' would therefore fall outside the remit of the Act.

Exemplar models

University of Manchester model

3.89. This model is described in Strbac's report, and is set out above. The model is at prototype stage and has not been used in practice.

EU approaches

3.90. The ISG considered charging approaches across the EU and concluded that the useful existing exemplars were very limited.

3.91. Newbery's report notes the differences between charging structures across the EU. Newbery notes that only Sweden levies GDUoS charges in the EU.

3.92. The majority of countries levy a shallow connection charge and recognise that DG brings the benefit of reduced losses and reduced reinforcement costs.

NGC DCLF ICRP model

3.93. NGC uses a transport model to calculate UoS charges to recover the cost of transmission assets and ongoing maintenance. The model is based on the assumption that requirements at system peak determine the level of investment required[18]. Generation customers generally[19] pay charges for their highest level of generation (Transmission Entry Capacity, TEC) in any year and HH metered customers pay for the highest demand at Triad (the three highest peaks of system demand in a year). NHH metered customers pay for energy usage on a kWh basis. The energy usage tariff is calculated from Triad.

3.94. The model is based on 1MW changes in the system at peak and the costs this imposes in relation to a reference node. The transport model takes in to account power flows and circuit impedance.

3.95. The ICRP model relates to the cost of investment in the system required to transport electricity securely at time of peak. The costs used in the model are for the transmission system at current prices, using a year-ahead model of the system.

3.96. The model aims to reflect marginal costs of demand and generation in different zones. The model provides locational cost signals, and tariffs vary year on year.

3.97. Views are invited on whether an ICRP-type model could be adopted for DNO use.

Transcost model

3.98. Transco uses the Transcost model to estimate the long run marginal cost of gas transmission capacity. Charges for use of the gas transmission system (NTS) for transmission owner activities are split to recover 50% from entry capacity and 50% from exit capacity. Entry capacity charges are based on auctions where

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[18] In a recent study (UoSCM-M-11) NGC found that of incremental investment in transmission assets, ~90% is driven by system peak demand conditions or peak generation capacity and ~10% is driven by year round conditions. Further information is available from http://www.nationalgrid.com/uk/indinfo/.

[19] Short term TECs were introduced by NGC from 1 November 2004 (modification UoSCM-M-13 and CAP070). The calculation of STTECs uses the 90% level explained in the footnote above.

minimum prices are calculated using Transcost LRMCs on the same principles as described below, but using a larger incremental capacity[20].

3.99. For exit capacity charges the Transcost model is used to calculate the additional costs of developing the system in order to transport an extra 100 million standard cubic feet (mscf) of gas from each entry point to each offtake point in each year for 10 years, based on a peak day demand scenario. This increment represents around 10% of flow along a route. Transcost is configured to change this increment as appropriate.

3.100. Only reinforcement required to cope with the extra demand is assessed (the 'incremental reinforcement') and not the reinforcement required due to load growth year on year ('base case reinforcement'). The long run cost for each route is the present value of the difference between the base network and the network extended by the increment. An optimisation procedure is carried out on the matrix of outputs for each route to determine a cost for each node.

3.101. It appears that this type of model could be applied to the electricity distribution system. However, the model would produce very large amounts of data due to the number of nodes on the system, and would be relatively difficult to set up and maintain year on year. The size of the incremental investment would also need to be determined.

Gas distribution network charging

3.102. Ofgem is currently carrying out a review of the structure of gas distribution charges and published an initial consultation paper on this in May 2004.

3.103. Transco recovers the costs relating to operation of the distribution network through DUoS charges using a postalised system for charging. Distribution charges are dependent on the size of customer load which acts as a proxy for the distribution assets used. Charges are set on the basis of the expected use made of

[20] Further details can be found in the 'Statement of the transmission transportation charging methodology' available from www.transco.co.uk.

distribution network assets by various types of customers. This is based on analysis of the average use of the system by different customers.

3.104. Further information regarding the calculation of gas distribution UoS charges is set out in the May 2004 consultation paper[21].

Views invited

3.105. Ofgem welcomes views on all the topics discussed in this chapter, including, for example:

- opinions on the most appropriate charging model to meet users' needs and to conform to the licence objectives;
- the extent to which it is appropriate to implement a fully economic model, how models could be adapted at lower voltages if necessary, and the extent to which incremental costs are appropriate; and
- whether respondents see any constraints on implementation of the models/charging mechanisms discussed in this chapter.

[21] 'Review of Transco's structure of distribution charges', (May 2004) reference 101/04, available from http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/gasdistcharges.

4. Detailed charging issues

4.1. As indicated in chapter 3, while charging models are the key element of the charge setting process, there are a number of other supplementary issues and processes that can have significant affect on customer charges. This chapter identifies some of those issues and considers how they should be incorporated in the longer term arrangements.

4.2. Some of these issues have been discussed in previous Ofgem documents, but most have not been dealt with in full for the interim arrangements. This chapter flags that these issues need to be considered in the early stages of the development of enduring arrangements. Issues are discussed in the following order:

- Connection charging boundary.
- Charge application issues:
  - Review of tariff structures;
  - Line loss factors;
  - Scaling of charges to revenues; and
  - Transition arrangements.
- Generation charging issues:
  - Arrangements for 2010;
  - DG and deferred expenditure;
  - Ancillary services and active system management; and
  - Reactive power charges (for both demand and generation).
- Development process issues:
  - Interaction between methodologies, and consistency between DNO areas;
  - Provision of charging model to users; and
  - Inclusion of independent DNOs (IDNOs) in methodology requirements.

4.3. As in chapter 3, views from the ISG, the academics and Ofgem are included where appropriate, and views are welcome on these opinions or on the most appropriate treatment for any of these issues.

Connection charging boundary

4.4. For the interim arrangements a common connection charging boundary was agreed for both demand and generation. A 'shallowish' connection charging boundary has been introduced, whereby the connectee pays for the new assets required to connect them to the existing network along with a proportion of network reinforcement if any is required. As part of the longer term arrangements it may be necessary to review whether the current boundary is appropriate.

4.5. The decision on the most appropriate connection charging boundary will be affected by the approach taken for the use of system charging model. As stated previously the longer term regime should seek to provide cost reflective locational signals which may allow for a 'shallow' connection charging boundary. In this context 'shallow' is considered to mean that the connection charge would not include any contribution to reinforcement of the existing system. However there are still questions to be answered as to the extent to which a cost reflective locational pricing model can be applied to the DNO network (as discussed in chapter 3) and whether the arrangements should be fully aligned between demand and generation.

4.6. Academic views on the boundary between connection and use of system varied. Turvey advocates deeper connection charges for generation as a means of ensuring cost reflectivity, whereas Newbery favours shallow connection charging as a more practical means of setting charges, and Strbac notes that a shallower connection boundary could be expected to aid the take up of distributed generation connections in comparison to a high connection charge which may serve as a barrier to entry.

4.7. Ofgem notes that the licence modifications that came into force in July 2004 do not prevent DNOs proposing changes to their methodology to apply a different connection charging boundary. Ofgem will consider any proposals to change the boundary alongside any changes to the UoS charging model.

Charge application issues

Tariff Structures

4.8. There are a large number of current DNO tariffs, many based on old Public Electricity Supply (PES) tariffs. A review of these is well overdue, since in some cases there is evidence that these tariffs no longer provide cost reflective signals. In addition there is currently a large degree of inconsistency between DNO tariffs, e.g. the mix of standing and unit based charges, and a clear basis for these differences needs to be identified and understood against the charging principles, given their impact on the supply market and end consumers.

4.9. Tariff structures will be mainly driven by the need to reflect costs to customers. This is discussed in detail in chapter 3 but it is likely that from the cost drivers considered, capacity (both for demand and generation) is a main driver, subject to time of use. Ofgem expects that charging models developed will reflect these costs. This may lead to a better understanding of differences between DNO tariff structures and may bring greater commonality of approach.

Metering constraints and price signals

4.10. However, there are other considerations, which will affect the structure of tariff design for all customers such as installed metering or billing systems. This is particularly important for non-half hourly metered customers, where existing systems are in place to provide a proxy for their use of capacity on the DNO's network through profiling. In the absence of a change in metering or settlement systems, a similar approach will be required in the future to convert kW or kVA of capacity into a kWh charge that can be billed. However, as stated earlier there is no restriction on charging capacity to half hourly customers and these tariffs can reflect the costs to customers more accurately and incentivise behaviour. For generation the same issues apply between the half hourly and non half hourly metering systems.

4.11. Some members of the ISG were concerned that due to the market structures in place, smaller customers would not be able to respond to these price signals both due to the use of profiling rather than half hourly meter reads but also due to the supplier interface. Demand customers' behaviour will ultimately only be affected by the supplier's charges, which will include other transportation costs and also energy and supply costs. Turvey notes that the suppliers will have little incentive to innovate their tariffs and to pass on more cost reflective charges to consumers unless the DNOs' charges become more reflective of long run marginal distribution costs. Ofgem agrees that the end consumer will be one step removed from the individual cost elements but considers that it is important that these elements that are charged to the supplier are cost reflective as far as practicable so that the supplier is then able to make a decision on how best to pass these costs on.

4.12. It is also important to consider what is being paid for through use of system charges and what right is conveyed. In transmission, generation use of system charges have historically been an annual product, where parties have to pay for a whole years charge independent of their actual use, based on a chargeable capacity. On the demand side, for HH customers it is their metered demand over the Triad while NHH customers are charged based on their consumption over peak periods during each year. For some distribution customers, longer term products to use the system may be attractive although contractual issues will need to be considered. Consideration needs to be given to the security of a party's connection and the access right being paid for through UoS charges in developing the charging models.

4.13. It is not necessarily expected that the outcome of this review will be many more tariffs, and indeed it may lead to stronger charge messages in fewer tariffs. However, it is likely that there will be changes and these changes will need to be communicated to all customers at the earliest opportunity.

Line loss factors

4.14. Line loss factors or loss adjustment factors as determined by DNOs are factors which convert a customer's consumption at their terminals to their equivalent consumption at the Grid Supply Point (GSP), in effect trying to replicate the level of losses that may be encountered across the DNO's network when supplying that particular customer. DNOs calculate these factors and they are used within the central settlement systems to determine the amount of energy required by suppliers and likewise the equivalent outputs from generators to the GSP. These factors do not affect how much the supplier or generator is charged for using the DNO's network or the DNO's revenue directly but they do affect users' costs. Ofgem intends to develop this issue further for a number of reasons.

4.15. As mentioned earlier the academic work highlighted a possible change to the main cost drivers for a DNO business. Historically the capital cost of equipment generally meant that investment decisions were made on the basis of the capacity required, but with the reduction in real terms of equipment prices and with the cost of losses generally staying constant, the cost of losses may become a larger determinant in the system development and design.

4.16. In addition recent issues, including customer complaints, have highlighted the need for greater transparency in the calculation of these factors - the methods used by the DNOs to calculate loss adjustment factors are not published or audited. Elexon have also voiced a concern that the Balancing and Settlement Code (BSC) Panel are currently responsible under the BSC (Section K) for approving the line loss factors that are used in settlement. They are concerned over this process in light of customer complaints and also the lack of transparency of the method of calculation process.

Information request – March 2005

4.17. On this basis Ofgem recently requested information from each of the DNOs on the method of calculation of loss adjustment factors. More detail of the methods used by the DNOs is set out at Appendix 2.

Next steps

4.18. Next steps will be determined following consideration of responses to this consultation, but it is Ofgem's initial view that the methodology should be more transparent, and could be included within the charging methodology statements in due course.

Scaling prices to revenues

4.19. Chapter 3 discusses options for developing a use of system charging model. Although different models are considered it is likely that whichever is used it will produce a set of charges that do not derive the DNO's allowed revenue. Therefore these prices will have to be adjusted or scaled to ensure that the DNO ultimately receives its allowed revenue. The level of mark up that will be required from a cost reflective model is not yet known, and will not be known until the DNOs bring forward prospective models.

Ramsey pricing

4.20. In terms of how this adjustment should be applied the academics were predominantly in favour of Ramsey pricing to achieve appropriate economic signals. This minimises distorting economic signals by applying the largest adjustment to those customers whose use of the network will be least affected by price changes (inelastic) and the smallest mark up to those whose behaviour is most affected by prices (elastic).

4.21. These issues have been discussed by the ISG. Significant concern was raised over the amount of adjustment that was likely to be applied and which customer groups may bear the potential mark up. The group also had concerns over the implementation of Ramsey pricing, in particular over how best to identify the elasticity of demand and how this would be applied on a simple basis to the DNOs network. It was recognised that approaches such as voltage of connection, or demand versus generation may not be the best determinant of elasticity and concern was raised over different elasticities within customer groups. It is clear that a robust method or research evidence would be needed to enable economic adjustments to be made in this manner.

Other options

4.22. One alternative approach to Ramsey pricing is to adjust the tariffs by a fixed amount to adjust them to the right level. This approach keeps the relative difference between the tariffs to different parties the same but the absolute level of charge varies. This approach is currently used in transmission charges.

4.23. Alternatively tariffs can be scaled using a percentage adjustment to all tariffs which may be viewed as a relatively simple, understandable and fair mechanism. However, this provides the largest disturbance from the economic signals provided by the model.

Demand and generation revenues

4.24. The revenue split between demand and generation has also been raised by members of the ISG. Currently demand customers bear the full cost of the distribution business but with the implementation of the distributed generation incentive arrangements and the connection of more generators, these generators will begin to bear some of these costs. At present these revenue streams are ring fenced but if common use of system charging models are developed, their effect may be to arbitrarily dilute the cost reflective price. It is Ofgem's intention that prices should reflect costs or benefits as far as is practical, and it may be appropriate (following the development of the longer term charging models) that the approach to price controlled allowed revenue is reviewed during the next price review.

Transition arrangements

4.25. The introduction of new charging models may lead to large disturbances in prices for some customers. It is important that this is considered when considering the approval and implementation of revised models.

4.26. As part of the implementation Ofgem will expect DNOs to consult fully with parties on potential changes to their methodology and as part of this to publish illustrative tariffs for any change proposals so that consumers and suppliers are aware of potential disturbances. DNOs should also consider suitable implementation dates when proposing modifications.

Generator charging issues

Arrangements for 2010

4.27. Generators connected prior to April 2005 will have paid deep connection charges under the prevailing arrangements at the time, which may or may not have included reinforcement costs depending on whether their connection triggered such costs. In any event, they connected at a time when distributed generators were not liable for charges for use of the distribution network and may have made decisions under the assumption that this policy would continue.

4.28. However, new charging arrangements apply to generators connected after April 2005, requiring them to pay a 'shallowish' connection charge and then pay DUoS for using the distribution network. In November 2003 Ofgem's initial decision document recognised that there were benefits to all generators being on the same arrangements going forward, to ensure provision of correct economic signals to the market and also for administrative reasons.

4.29. It was concluded at that time as a practical way forward that for generators connected prior to April 2005 there should be a transition to the new arrangements and they should receive a full rebate against any use of system charges they would otherwise face in the period to 2010. However generators could choose to opt in to the new arrangements.

4.30. As part of the longer term arrangements, Ofgem committed to reviewing the position from 2010. Ofgem has considered the issues and believes that it is still beneficial for all generators to be on the same charging arrangements and therefore is minded to support the transition of these generators onto the new arrangements by 2010. From 2010 the charging arrangements for all distributed generation therefore would be aligned so that any distortions were removed and cost reflective charging was applied to all parties.

4.31. Consideration, and in some cases appropriate recognition, will need to be made of the existing rights of generators connected prior to April 2005 (who in some cases may have access to use the distribution system for an undefined period) and to ensuring that parties will not be double charged for this access going forward. Two possible alternative approaches to address this are outlined below.

Value of access right

4.32. One approach would be to assess the current value of the access right to use the distribution network for individual parties. This access right could then be assigned to the individual generators, not only to facilitate the generator trading their right to other parties but also to ensure that all parties would be provided with efficient cost signals going forward. The value of these rights would be derived on the same basis as the charges going forward and therefore could only be derived once an economic model had been developed.

Historic cost adjustment

4.33. This would require a review of the historic costs of connection of each party and a comparison of these to the current connection charging boundary. In this case any differences could be valued and accounted for as an annuity rebated against the ongoing GDUoS charges. Therefore in the cases where generators had paid a significant contribution through deep connection charges, the difference in the level of charge as compared to the shallowish arrangements could be assessed and the values annuitised where appropriate (i.e. the costs that would be captured through use of system charges). In cases where there were no reinforcement works at the time of connection then the generator going forward would be liable for DUoS with no rebate.

4.34. Either of these approaches would need to be developed in detail and both have limitations that would need to be addressed but in doing so it would allow for a consistent charging framework beyond 2010. As discussed below it is expected that economic models developed will not only provide cost reflective charges but they should also identify any potential benefits provided by users. It is therefore unclear at this stage what the impact for different parties will be of moving to consistent generator charging arrangements but it in any event, as stated in previous documents, generators connected prior to April 2005 should be allowed to opt into the new arrangements.

Distributed generation and deferred expenditure

4.35. With the majority of distribution network currently installed for demand it is likely, in the first instance, to be generation that provides benefits to the network through potential for deferred expenditure. However, in principle demand customers could also defer network expenditure. As outlined by the academics, it is not just incremental cost that should be assessed but also the net savings that parties might bring to the network. As discussed in Chapter 3 the development of economic models will enable such benefits to be identified and valued.

4.36. However, in developing charges that reflect benefits that parties bring, some issues need to be considered, for instance whether charges can be negative or should be capped at zero. In particular, if negative demand charges are developed, consideration would need to be given to any potentially perverse incentives concerning energy efficiency that could occur. Negative charges would be reflecting a benefit that a party might bring to the network over time, dependent on their behaviour. Therefore, it may not be appropriate to make payments to parties based on assumed behaviour but rather based on their actual behaviour, to ensure that pricing signals are acted on. To avoid potential contractual security issues consideration needs to be given to the most appropriate format of these charges. For example, using ex post arrangements may avoid potential contractual security issues, but this may become unwieldy dependent on the number of parties.

4.37. This is an area that needs further consideration, particularly on identifying means to provide cost reflective signals to parties further down the distribution networks, e.g. NHH billed customers. For instance industry research[22] indicates that microgeneration is likely to reduce the demand on the distribution network and although it may impose some costs as well, it will provide in general long

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[22] 'System integration of microgeneration – costs and benefits', Mott MacDonald, July 2004

term net benefits. It will be necessary to quantify this and identify means of monitoring these connections so that the benefits can be passed on.

Ancillary services and active system management

4.38. ISG discussions and the academics have both raised the issue of ancillary services. There may be cases where generation is able to provide support to the local network (e.g. through reactive support) on a contractual basis which may be more economic than the DNO installing plant or equipment. Further consideration should be given to a framework in which such arrangements can develop but this is considered to be beyond the scope of this review.

4.39. The academics also raised the question of active system management. In the absence of a design security standard for connection of generation at distribution and scope for flexibility in approach there may be occasions where the generator may wish to have a 'lower' security of connection to avoid extensive network upgrades. Under certain conditions these parties would be disconnected from the system to ensure that the system remained intact. The academics question whether in these situations these parties should be entitled to a lower or special interruptible tariff. Ofgem believes that such charging arrangements are likely to be complex to implement as each connection will be different, but that this issue should be considered.

Reactive power charges (demand and generation)

Incentivising behaviour

4.40. Ofgem considers it important that connected parties using the distribution network are encouraged to operate their connections near unity power factor to ensure efficient use of the system. In general this will ensure available capacity is maximised, avoid requirement for early capital expenditure in reinforcing the network and also avoid increasing losses on the system.

4.41. In most situations poor power factors associated with demand connections lead to additional costs and it is important that the DNO accurately reflects these costs such that customers can make the decision as to whether to amend their power factor on site, through some form of reactive compensation, or contribute to the costs that the DNO bears due to their connection. It is important for the longer term arrangements to identify a simple way of establishing these costs and providing cost reflective charges.

4.42. If the main cost driver is found to be capacity it is possible to value poor power factors by charging on the basis of kVA. Although some DNOs already do this for their HH customers this in general may only account for half the customer's charge (subject to their energy usage) as the customer charge is in general also made up of a unit based tariff and some form of standing charge. This provides only a weak cost reflective charge. Therefore, where metering permits, Ofgem would expect DNOs to derive suitable outputs and tariffs from their UoS models to adequately reflect these costs.

4.43. As mentioned above poor power factors may lead to costs other than at peak times on the network and it is important that these are also considered by DNOs. A consumer with a poor power factor may lead to increased losses on the network, however as happens now the DNO is able to apply a site specific loss adjustment factor which will reflect this. In this situation the site specific loss adjustment factor will not only reflect the location of a site but also its power factor. By doing this the additional costs will be reflected through to the user. A greater degree of visibility of this approach to consumers will ensure that least cost economic decisions are made by the end consumer and this supports the DNOs in providing greater visibility to their loss adjustment factor methodology.

Generator power factor

4.44. In the case of generators, the above issues may not hold true, and in some cases the generation can be used to reduce losses on the network. In a lot of cases, the generator itself can manage its power factor and in some cases may provide a positive contribution to a network thereby avoiding investment. Further consideration is needed to determine the most appropriate mechanism to charge or reward generator reactive power. It is not clear that a one size fits all approach for demand and generation is appropriate.

Metering

4.45. ISG members have raised a concern that the current metering codes of practice (which detail the necessary metering specifications) are not adequate for distributed generators, particularly where one supplier acts for the import to a site while another supplier contracts for the output of the site. A review of this will need to be undertaken to ensure that effective contractual, metering and charging arrangements are available for charging generator reactive power.

Development process issues

Interaction and consistency of methodologies

Consistency between DNO areas/models

4.46. Differences in methodologies across DNOs could potentially distort siting decisions for new generators or demand customers. It is recognised that even if DNOs have the same charging methodology, the charges are likely to be different simply because of revenue requirements, although it is expected that this distortion will be limited.

4.47. Ofgem considers that there would be benefit in the DNOs working together to provide consistent charging models. Consistent models would reduce implementation costs and might aid comparison of tariffs between DNO areas and promote clear inter-DNO locational signals and may reduce supplier costs in assimilating DNO tariffs.

4.48. It will be for the DNOs to present solutions in line with their licence obligations through proposed modifications to their charging methodologies, with Ofgem/the Authority acting as the approval body. This could see the development of more than one charging model. Ofgem notes that there may be a trade off between consistency of approach between DNOs and the promotion of innovative charging solutions by individual DNOs.

Interaction between transmission and distribution charging

4.49. When comparing transmission charging to distribution, it is recognised that there are some significant differences between the arrangements which may cause different incentives. Although there are these different approaches between the two systems, as long as both transmission and distribution charges reflect the actual costs imposed by a party on each level of the system, then a balance should be achieved and the two charging regimes should interact harmoniously.

4.50. The greater concern is that in some cases the transmission costs are not being reflected to parties, which in turn is causing potentially uneconomic behaviour. Generation connected to the distribution system will affect load flows and therefore long run costs on the transmission system. Under the current transmission charging rules, these generators may not be charged for these costs, potentially allowing uneconomic connections to proceed, or incentivising parties to connect at distribution level.

4.51. Although this issue is outside the scope of this project, it is intended that this work will be taken forward by Ofgem and consulted on later this year. Any issues arising from this review which impact on distribution charging will be considered at that time.

Provision of charging model to users

4.52. Historically distribution charges have generally been relatively stable. This could be due to a number of reasons, and it is not clear that this was solely because underlying costs were stable. For parties to be better aware of the likely changes in charges that may happen over time it is important for the methodologies to be transparent and their application predictable.

4.53. Although publishing the charging methodologies has allowed greater transparency, some users have suggested that this could go further, and have requested access to the DNO charging models. Parties would therefore be better informed of how the model works and be able to make judgements on the 'unknowns'. While charges may not necessarily be stable they should be more predictable.

4.54. For the interim arrangements, DNOs commented that their models were not in a suitable format to be made available to parties. With the development of charging models for the longer term arrangements, Ofgem would support the availability of these models, albeit recognising any limitations due to commercially sensitive data.

IDNO charges and methodologies

4.55. Three new distributors were granted licences in 2004 and arrangements put in place for them to contract for UoS. A recent initial proposals document on the regulation of IDNOs[23] considered these contractual arrangements, which currently require suppliers for end consumers to enter into one contract only with the IDNO, covering both the DUoS charge for the IDNO network and also the upstream charge for use of the DNO's network. The IDNO then contracts with the upstream DNO in order for the DNO to recover its share of the end charge. It is important to for the DNOs' methodologies to establish the method of calculating this share so that there is a transparent basis for the charge between the two distributors, and to ensure that these arrangements are effective.

4.56. In addition it is worth noting that SLC4 applies to IDNOs as well as DNOs, meaning that they are required to produce charging methodologies both for connection and use of system charges.

Views invited

4.57. Views are invited on all the issues in this chapter, including how these relate to the application of the various charging models discussed in chapter 3.

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[23] 'Regulation of Independent Electricity Distribution Network Operators – Initial Proposals', Reference 18/05, January 2005 available from http://www.ofgem.gov.uk/ofgem/work/index.jsp?section=/areasofwork/idno

5. Impact assessment

5.1. Although Ofgem is currently leading this development work with the industry, it will be for the DNOs to develop solutions to the charging issues discussed in this document. These solutions will be commercial initiatives rather than regulatory policy, and new arrangements will be proposed as modifications to the UoS and connection charging methodologies. As part of the process for approving or vetoing the modifications, Ofgem will consider the impacts of these changes when they are put forward by the DNOs, consulting where necessary on the likely costs and benefits of each proposal.

5.2. Section 5A of the Utilities Act obliges Ofgem to carry out an impact assessment where the Authority is intending to carry out one of its functions under the Electricity Act, or where the proposal will have significant impacts on any industry participants, the general public or the environment. This document, and the conclusions document to be published in the summer, both indicate an Ofgem view rather than initiating a project or implementing a policy, and therefore it is not proposed to carry out a formal impact assessment. If any parties feel that more formal assessment is necessary, they should explain this in their responses.

Views invited – costs and benefits

5.3. However, Ofgem would appreciate views on costs and benefits where parties feel that these may be important in reaching conclusions about the most appropriate high level structure and timetable for the long term arrangements. Ofgem considers that, for the purposes of formulating a view for the summer conclusions document, some of the areas where cost impacts may be important are:

- ♦ the extent to which the DNOs should work together:
    - o joint working may reduce development costs for DNOs,

- however, joint working may stifle innovation: there may be multiple solutions to the same issues, or reasons why differences between DNO approaches/areas are appropriate.

♦ whether a common charging methodology between DNOs is appropriate:
  - commonality between approaches is likely to have benefits for suppliers and customers in understanding the charge setting process and billing the resulting charges, and
  - commonality between DNO areas could decrease the likelihood of cross-boundary discrimination or inconsistency of charges

♦ the timing of implementation for the longer term arrangements:
  - three of the DNOs[24] have conditional approvals on their UoS charging methodologies relating to their charging models, with deadlines of 1 April 2006: how do respondents consider that this will interact with the development of the longer term framework?
  - Ofgem has indicated that it expects revised arrangements to be in place as soon as possible, and no later than 2010. Do respondents consider that there are benefits to either earlier or later implementation?
  - do parties (DNOs/suppliers/customers) consider that there are any contractual issues regarding the timing of implementation of revised arrangements?

♦ possible interactions with other events/projects that may affect the implementation of new charging arrangements, including, for example:
  - further development of revised governance arrangements, and
  - lead up to the next distribution price control review (DPCR5) in 2010.

[24] CE, CN and EDF Energy. More details of the conditions are contained in the February decision documents.

5.4. As set out above, the costs and benefits of each modification to the charging methodologies will also be considered individually, so there will be further opportunities for affected parties and Ofgem to reconsider costs and benefits in the future as these become clearer. However, responses on these issues will be very useful in developing Ofgem's views.

6. Implementation

Project leadership

6.1. The timescales associated with the development of this stage of the structure of charges project are briefly outlined in chapter 2. Ofgem is currently leading the development of the longer term charging arrangements and is working with the industry both through the ISG and consultation documents to develop a high level framework of enduring charging arrangements. It is expected that this work will continue through the summer, when Ofgem intends to publish a further document setting out its conclusions on the high level structure in more detail. Mindful of the fact that this document will constitute Ofgem's conclusions on the principles for the long term, Ofgem is keen to capture as many views as possible now – through the current consultation and through a public workshop to discuss charging issues. Details of the workshop are attached at Appendix 1.

6.2. It is likely that the development of the longer term arrangements will then continue through the course of 2005 and into 2006, but this work will be more focused upon implementation. This stage of the work will not be led by Ofgem but by the DNOs. The DNOs will need to consider (either collectively or individually) how best to meet the high level proposals laid down by Ofgem to ensure that they continue to develop their methodologies in line with the relevant objectives. Ofgem's role will be one of supporting the industry as the implementation phase of the longer term arrangements begins.

Future methodology development

6.3. The longer term framework will be facilitated through changes proposed by the DNOs to their methodologies. In addition to these major changes, the DNOs may also bring forward other changes as review of the methodologies shows that they could be improved in other ways[25]. Changes must be approved by the

[25] SLC4(2) and 4B(2) require the DNO to review their charging methodologies at least once a year and make changes to it that help it better achieve the relevant objectives.

Authority in accordance with SLC4(4-6) and 4B(10-12). The Authority's decisions will be based on consideration of the relevant objectives and its wider statutory duties.

6.4. Any proposed modification to the methodology must be presented to the Authority with an explanation of how it better achieves the relevant objectives. The Authority then has 28 days to veto such a change, unless within those 28 days it notifies the licensee that it intends to consult. Following this notification, the Authority then has a further three months to announce a decision on whether to approve or veto the change.

6.5. The current situation on the transmission system is that NGC conducts its own consultations on proposed changed to the charging methodology. This solution is not necessarily practical for distribution, given that there are fourteen network owners (plus three IDNOs) rather than one.

6.6. However, while it is recognised that centralised consultation may be more appropriate for changes which concern multiple DNOs, Ofgem also considers that in some cases, especially where the change is specific to the licensee, the more efficient solution will be for the DNO to consult with its customers and any other interested/affected parties on the modification. SLC4(6)b and 4B(12)b exist as a safeguard to ensure that the industry can consider material changes where they have not been subject to prior consultation by the DNO.

6.7. Ofgem envisages that it will be important for DNO consultations to:

- reach as wide an audience as possible, and at the very least include all those contracted for UoS with the DNO,
- set out:
  - a clear explanation of the proposed change, and of how it meets the relevant objectives,
  - the date from which the change would apply,
  - proposed wording for the methodology statement,

- any effect on charges, or resulting changes to the UoS charging statement, and
- a reasonable deadline and a clear procedure for responding[26].

6.8. Responses would then be used to inform the modification proposal submitted to the Authority, and the Authority will consider these responses as part of its decision on whether to approve the modification.

6.9. In addition to these changes, some of the DNO UoS charging methodologies still have conditions attached to their approval[27]. The latest deadline for these is 1 April 2006, and Ofgem expects that changes will be proposed by the DNOs to cover off these conditions before this date. Ofgem will liaise with these DNOs on a regular basis to ensure that the actions are being progressed.

Role of the ISG

6.10. All of the above areas are likely to lead to a changing role for the ISG during the course of 2005. The ISG was established to provide expert opinion and act as a sounding board in the development and then implementation of the interim charging arrangements, and will continue to support the development of the longer term arrangements.

6.11. With the changes and developments mentioned above it is likely that an industry group will be necessary but the structure and terms of reference will need to change. Ofgem want as much collaborative work as possible on the development of new methodologies and central consideration of issues at an industry group would aid this process.

6.12. Views are sort on the most appropriate way forward for the ISG, its successor or the need for other industry groups.

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[26] This list is informed by Ofgem consultation practice and NGC's format for transmission charging methodology change proposal consultations.
[27] These relate to the production of more cost reflective charging models (CE, CN and EDF – 1 April 2006), EHV transition strategies for April 2006 (CE, WPD, EDF and UU – 1 October 2005), and the unmerging of NHH LV domestic and non domestic tariffs in the Eastern area (EDF – by 1 April 2006).

Distribution commercial governance

6.13. Ofgem and the industry are currently considering the options for centralised distribution commercial governance and standardised terms for UoS. A Distribution Commercial Forum (DCF) has also been established. It is not envisaged that the SLC4 charging statements and methodologies (which have their own licence-based change processes) will be part of this process, but it is recognised that the two areas are related, and charging issues are central to both.

6.14. For example, the governance project will be looking at the terms for UoS (the current DUoS agreements – the DUoSAs) and how standard terms should look. As the means by which UoS and GDUoS charges are billed, it will be important to ensure that these contractual arrangements will correctly facilitate any new long term charging arrangements that are implemented.

6.15. The ongoing development of the structure of charges will need to keep abreast of the discussions in the DCF and the development of the governance project. Ofgem will work with the industry to ensure that the development of each project is informed of progress on the other.

Appendix 1 Structure of charges public workshop

Date: Tuesday 24 May 2005

Time: 10am to 4pm

Venue: Ofgem offices, 9 Millbank, London SW1P 3GE. Lunch will be provided.

Ofgem is intending to hold a workshop to discuss the issues contained in this paper and to aid industry in forming views in advance of the deadline for submission of responses.

The approximate format of the day will be:

- **Introduction** from Ofgem:
    - summary of key themes from the May 2005 consultation document, and
    - timetable for 2005.

The workshop will then split for the **morning session** into:

- Breakout session 1: charging models and cost drivers, commonality and consistency between models and/or DNO areas, IDNO charging methodologies, publication of models.
- Breakout session 2: transitions, generator charging from 2010, reflecting benefits of DG, interaction with transmission charging.
- Breakout session 3: metering/billing issues, tariff structures, scaling, LLFs, metering, IDNO charging.

Each group will nominate its chair and then discuss the issues. Then, for the **afternoon session**:

- Group chairs report back to main workshop, followed by workshop discussion session for each group's topics.

- General discussion time for any other business (eg timetable, establishment of charging methodology forum/future of ISG).

- **Close** from Ofgem.

The intention of the afternoon session is to allow debate on all the issues discussed during the morning, in case there are attendees who would have liked to have been involved in more than one of the groups.

If you are interested in attending the workshop, please contact Clover Powell on clover.powell@ofgem.gov.uk or 020 7901 7210 by close of play on **Friday 13 May 2005**, indicating which breakout session you would like to attend.

Given the broad scope of the issues being discussed, and the number of breakout sessions, multiple attendees from companies/organisations are welcome, where necessary.

In the event of the workshop being oversubscribed, Ofgem will allot spaces on a first come first served basis.

Appendix 2 Losses

This appendix considers key policy issues concerning losses. Ofgem would like comments on line loss factors (LLFs) to inform our policy position following Ofgem's information request to the DNOs on 8 March 2005, and the subsequent submission of LLF methodologies by the DNOs in April.

The method for determining LLFs is not currently published by any DNO. Loss factors are a fundamental part of the settlements system managed by Elexon and have an impact on consumer charges.

As set out in chapter 4, LLFs are determined by the DNOs and convert a customer's consumption at their terminals to their equivalent consumption at the Grid Supply Point (GSP). LLFs are used within the central settlement systems to determine the amount of energy required by suppliers and likewise the equivalent outputs from generators to the GSP. These factors do not affect how much the supplier or generator is charged for using the DNO's network or the DNO's revenue directly but they do affect users' costs.

Ofgem intends to develop this issue further for a number of reasons, including:

- Academic comments that losses may be a key cost driver in determining system investment.
- Customer complaints which have highlighted the need for greater transparency in the calculation of these factors (the methods used to calculate LLFs are not published or audited).
- Elexon have raised concerns that the Balancing and Settlement Code (BSC) Panel are currently responsible under the BSC (Section K) for approving the LLFs that are used in settlement, and they are concerned over this process in light of customer complaints and also the lack of transparency of the method of calculation process.

Information request

Ofgem wrote to the DNOs on 8 March to inform them that it was initiating a review of the methods used for calculating line loss factors (LLFs) and intended to consult with the industry on these methods to ensure greater transparency in the basis by which LLFs are formulated.

In the information request letter, Ofgem stated the intention to provide greater comfort to industry participants on the basis of LLF formulation as well as to promote a wider understanding of the method of calculation and the approach used by the DNOs in the calculation of LLFs.

Ofgem asked each DNO to set out the methodology it uses for the calculation of LLFs by 8 April 2005.

The method of calculating the factors differs between DNOs. The majority of DNOs calculate site specific loss factors at EHV using individual load studies and generic factors split by voltage for other connections. Loss factors are based on fixed losses (associated with plant and equipment) and variable losses (associated with energy flow). Some DNOs use simpler allocation methods. Ofgem notes that some DNOs include theft in the loss factor calculation whilst others calculate purely electrical losses.

Many of the DNOs use software developed by EA Technology in the late 1990s to calculate generic LLFs. This program calculates loss factors for each half hourly period of the year by adjusting losses until power coming in at a voltage/transformation level is equal to power going out at that level. Half hourly data is derived from metered data using settlement profiles. The half hourly loss factors are aggregated to form composite factors.

The issues and questions below are designed to seek views on the issues raised by the LLF methodology submissions. As mentioned above, these methodologies are not currently published by the DNOs. Ofgem awaits responses from this consultation to determine next steps.

Questions

Ofgem notes that the distribution licence requires DNOs to publish line loss factors in their statement of use of system charges (SLC 4A(2)b). In addition, this statement has to be prepared in accordance with the use of system charging methodology (SLC 4A(1)b). The use of system methodology has to be prepared in line with the charging principles set out in the licence. These are cost reflectivity, the facilitation of competition, taking account of changes in the DNO's business and ensuring the discharge of licence obligations:

- Should the methodology for calculating loss factors be included in the use of system charging methodology published by each DNO and be subject to the governance of the charging methodologies?

DNOs currently adopt different methods for calculating loss factors. These vary in sophistication. Most calculate site specific factors for certain customers, generally at EHV and for large or unusual connections. Generic factors at other voltage levels are based on different allocation methodologies:

- Should a consistent methodology be adopted for the calculation of losses by all DNOs?

- Can a non-site specific approach be justified? Which customers should have site specific loss factors?

- Should loss factors be determined in the same way for distributed generation as for demand?

Losses definition: Some of the DNOs base their loss factors on technical losses only whilst other DNOs include all categories of losses in their calculation, including theft:

- Should loss factors include only electrical losses or should they include all categories of losses?

IDNO requirement to submit LLFs:

- Should IDNOs calculate losses on the IDNO system in the same manner as the DNOs?

Ofgem welcomes comments on any other issues relating to losses:

- Are there any other issues that need considering in the review of LLFs?