Delivering the electricity distribution structure of charges project
Response by SP Energy Networks May 2008

Introduction and Summary

SP Energy Networks ('SPEN'), on behalf of SP Distribution and SP Manweb, welcomes the opportunity to comment on the issues raised in this consultation.

SPEN has been working since 2006 with other DNOs, latterly as part of the G3 project (together with SSE Power Distribution and Central Networks), on long term methodology for Use of System charging, and we have recently submitted a modification proposal for approval and implementation by 1 April 2009.

This is a complex area, and we and other DNOs have put considerable resources into modelling and developing methodologies that are more attuned to current market and network conditions, and in particular provide greater cost reflectivity in respect of Distributed Generation (DG). While we have incurred significant costs in carrying out this work (for which we would expect recovery),` the G3 group of 6 DNOs – almost half the industry – has developed an approach that we believe meets existing licence requirements as well as the high level principles that Ofgem has set out.

Although we recognise the perceived attractions to users of a common detailed methodology, any imposed common methodology would have to be capable of satisfactorily accommodating differences among DNOs. Licensees do not all use the same network analysis tools and the degree of scripting varies. Also, data availability on power flows and the ability to undertake nodal analysis will vary.

In addition a common methodology would have to be applicable to a variety of network architectures, including both radial and interconnected networks (for example, SP Manweb's network is more interconnected than for most DNOs). For interconnected networks the concept of a nodal approach has less relevance.

We believe that a common methodology clause in the Licence Modification will mean a delay in the process and undo much of the work already underway by the DNOs. It would also entail significant additional costs for DNOs that would need to be recovered. We believe that one factor that would better assist companies in bringing forward methodologies that are fit for purpose is for Ofgem to provide clearer guidance on criteria for approval of methodologies (we comment below on the some difficulties with the Relevant Principles as drafted).

We recognise the case for forward looking incremental costs as a basis for charging methodologies, and that LRIC has been put forward as one such approach. However there seems to be lack of clarity in relation to the LRIC method. In practice, there are severe difficulties in applying a LRIC method as interpreted by Bath University (and implemented by WPD) in circumstances of low or negative growth (such as have been experienced in many parts of GB in recent years). It is also does not deal at present with costs driven by fault levels. It does not allow for recognition of the “lumpy” nature of generation, and therefore has a limited scope for cost-reflectivity in such cases. Due to these difficulties, such an approach can yield charges in certain circumstances that could be considered excessive and even open to challenge under competition law.

We believe that the G3 methodology addresses these difficulties while meeting also the high level principles of transparency, simplicity and predictability set out in chapter 2 of the consultation paper. Appendix 1 provides a summary of the G3 approach.

We believe that there is a good case for Ofgem to consult on and then issue detailed guidance on charging methodologies. However, the Relevant Principles as proposed in the consultation paper fall short of what is needed in a number of respects. For example, they do not address the trade-offs between different factors involved (such as ‘reflecting all significant cost drivers’ and being ‘predictable to network customers’). The term ‘forward looking incremental cost’ is not defined and is subject to a range of possible interpretations as mentioned above.

Following on from this, the process as proposed gives rise to a number of governance concerns. In particular, companies could find themselves unable, despite their best efforts, to meet the 1 October 2009 deadline if the Authority did not approve submissions by 1 July, perhaps as a result of comments made by third parties during the consultation period.

An important issue mentioned in passing in the paper is the current “two pots” price control for load and generation. This approach means that any benefits identified by a generation charging methodology will be paid for by other existing generation users and not the demand customers whose reinforcement costs generation is considered to displace or defer. This issue should be addressed in any long term solution for charging methodologies.

Our proposed way forward in the light of these considerations is for Ofgem to consider current and forthcoming submissions from companies under existing licence arrangements. It should consult on and issue detailed guidance to companies on criteria for approval and implement a new deadline for submission of longer term methodologies only for companies where these are outstanding at that time.

This approach has the best prospects of retaining the benefits of work already carried out by companies and achieving as early an implementation of longer term charging methodologies as possible.

With this as background, our comments on the specific questions raised in the paper are as follows.

Chapter 1 – Introduction

Question 1: case for licence obligation to deliver UoS charging methodologies that meet required principles and objectives by 1 October 2009

We are concerned at the obligation to have an *approved* methodology in place by a fixed date.

We believe that there are serious governance and process issues with the proposed approach. Even if all DNOs were able to submit a methodology according to their current individual progress by April 2009 or develop and submit a common one within similar timescales, a negative decision by the Authority in July 2009 (after a period of consultation) could effectively put all of them in breach of the proposed licence condition – as there would not then be time to go through another 3 month consultation period prior to 1 October 2009.

Given that most DNOs are already at an advanced stage of developing their longer term charging methodology, our concern with regards to a licence modification is even greater if such modification calls for a common methodology. This issue is compounded by DNOs' previous experience of the modification process. We note the comment in paragraph 1.3 that only Western Power Distribution's two DNO areas have a revised methodology in place, although these do not yet address generator charging at HV and LV. We have been working with other DNOs, particularly in the G3 group, over a number of years, and we have submitted a methodology for approval that takes account of generator charging at all voltage levels. The G3 have spent around 2 years in developing the methodology submitted by SPEN in May 2008 and believe that developing a common methodology across all DNOs is not attainable within the proposed timescales, as discussed in Question 4 below.

We believe that a great part of the perceived excessive time taken to submit the different DNO's modifications (and the so-called failure to meet deadlines mentioned in the consultation paper) has been due to the complexity of this particular area (with sometimes conflicting high level principles), as well as lack of clarity on the criteria that will be applied to assess the proposals. We believe that this lack of clarity has reduced confidence that a particular modification would be approved and also may have caused efforts to be concentrated in the wrong areas.

Chapter 2 – High level principles

Question 2: has Ofgem considered all necessary high level principles and objectives for structure of charges project going forward?

We note the high level principles, originally set out by the ISG in 2005. It is important to restate the fact that there is a certain degree of "tension" between the principles (for instance between the principle of cost reflectivity and the principles of simplicity, transparency and predictability). Nevertheless, it is encouraging that Ofgem have continued to refer to the need to achieve a balance between these principles.

In general, more detailed guidance to DNOs on criteria for approval of any modification proposal would be helpful. Although the 'Relevant Principles' in the proposed licence drafting are a step in this direction, as drafted these are capable of a number of different interpretations and they do not set out how the mentioned potential conflicts between different priorities would be resolved.

The proposed Relevant Principles seem to be developed from a theoretical approach to charging, and follow closely the recommendations made by academics to Ofgem in 2005. However, it is likely that there will be difficulties in implementation of the principles as they stand. The RPs do not indicate how potential conflicts between different priorities are to be resolved – e.g. how to reconcile the requirement to 'accurately reflect network costs' with providing 'transparency' and 'predictability'. Also, there is an apparent inconsistency in the use of terms, including "forward looking incremental costs", "forward looking costs from incremental use", "incremental costs", "network costs incurred" and "marginal costs". It is not at all clear which of these are intended to be identical and which are different from each other.

In particular, we have the following detailed comments on the proposed Relevant Principles:

Principle 1(b): *A common charging model for both demand and generation.* The principle as it stands is very vague on the meaning of applicability to "both generation and demand". It goes further to state (in subparagraph ii) that the charges shall be calculated "on an equitable basis". This term is vague and it could lead to confusion on what is required. We agree that the charging models should accommodate both demand and generation, but it should also be able to recognise and reflect accurately the underlying characteristics and differences of each of them. Given the "lumpiness" of generation growth (as oppose to a smoother growth seen in demand) it is necessary for the model to accommodate this in a cost reflective way. This cannot be achieved if the model is constrained to simply treat generation as negative demand.

Principle 1 (c): *A forward looking incremental cost model.* We agree with the view that the charges should be based on forward looking costs in order to influence future behaviour. However the term "Forward looking incremental costs" is not defined and is open to a number of interpretations We are minded that, under certain implementations of a forward looking charging signal, the resulting charges can be seem as excessive and non-cost reflective and therefore have implications under competition law. For more detail on this point, as well as an example of such potentially excessive charges, refer to Appendix 2. Furthermore, the link between estimates of forward looking incremental costs and the calculation of annual charges is opaque

Principle 1(d): *Cost reflectivity and cost drivers*. It is important to ensure not only that the correct cost drivers are identified, but also that the resulting charging function behaves in a way that reflects the profile of costs and ensures that the right signals are given with an appropriate degree of strength. A cost-reflective charging function should have a set of desirable properties (as detailed in appendix 1 below). For example, the charge signal should tend to zero as growth tends to zero.

Principle 1(g): *Scaling approach which minimises distortion.* We agree, in general, with a principle for scaling which distorts as little as possible the pricing signals derived from a forward-looking methodology. However it is important to keep in mind what scaling is for and what costs are reflected in scaling. When using a forward-looking charging method, scaling reflects costs that are not taken into account in the modelling, which are principally asset-related historic costs, such as depreciation and return on capital employed. Given the nature of these costs, it is inappropriate to add them equally to all tariffs, as it would effectively impose costs relating to the lower network voltages onto higher voltage customers, making their charges disproportionately high. This contradicts the principle of cost reflectivity and also could have implications under the Competition Act.

In relation to an LRIC methodology it should be noted that SP takes the view that, under certain implementation arrangements of the LRIC, it could lead to potentially excessive charges. It is important to ensure as far as possible that compliance with the Relevant Principles (or other guidance on charging methodology) does not expose companies to a potential breach of competition law.

Question 3: Has the structure of charges project highlighted any objectives set out that are not appropriate for project going forward?

We think that the objectives highlighted to date are all appropriate going forward.

However, as set out in our comments on question 2 and also in appendix 2, we are concerned about the implementation of the forward looking incremental cost concept. In particular, in certain circumstances, an incremental cost approach may give rise to potentially excessive charges that may be open to challenge under competition law. It is also of concern that the implementation of an LRIC method could serve to over-simplify the effect of generation in the system, by not taking into account the fact that it comes into the network in larger steps (as opposed to a smoother growth pattern more commonly seen for demand).

Chapter 3 Options for structure of charges project

Question 4: Views on two options presented and timescales

We believe that a requirement to develop a common methodology that will be applicable to all DNOs by July 2009 is unlikely to be practicable. However, an existing methodology that meets the high level principles may be adaptable across DNOs. We believe that the G3 methodology fulfils these requirements. However, a formal licence requirement for a common methodology is not appropriate.

Any imposed common methodology would have to be capable of satisfactorily accommodating differences among DNOs. Firstly, licensees do not all use the same network analysis tools and the degree of scripting varies. Also, data availability on power flows and the ability to undertake nodal analysis will vary, as this will depend on the configuration of the network and its level of interconnectivity.

Secondly, there is considerable variability of growth rates both across and within DNO areas, with some areas already facing falling demand. As we move to a low carbon economy, it is likely that demand will fall in more areas. This raises particular issues with the LRIC methodology, which is sensitive to the assumed growth rates.

Thirdly, our network analysis indicates that fault levels are a significant driver of reinforcement costs, as well as thermal capacity. In addition, AC load flow analysis also takes into account reactive power, which has a significant effect on network costs and energy losses. Furthermore, distributed generation gives rise to the potential for reverse power flows, depending on the balance of generation and demand on a particular feeder. Considering all of these aspects will improve cost reflectivity but their relative importance will vary across networks.

As regards the proposed Relevant Principles to be met under either common or DNO-specific methodologies, these are not, in our view appropriate, at least in their current form, for a number of reasons as detailed in our response to Question 3 above.

It would be preferable, in our view, for Ofgem to consult on and then issue guidance to companies on criteria for approval that avoided the difficulties with the Relevant Principles as drafted.

Question 5: Views on implementing two options

As set out in detail in our response to Question 1 above, we have serious concerns over the proposal for an approved methodology, whether common or DNO-specific, to be in place by 1 October 2009 that meets the Regulatory Principles set out in the paper.

Conclusion

Given the detailed points made above, our suggested way forward is as follows.

- **Ofgem to consider current and forthcoming DNO proposed methodologies under existing licence requirements and stated high level principles;**
- **Guidance document (not in licence) to be issued after consultation that provides clarity on Ofgem's detailed criteria for approval while avoiding definitional and other difficulties with Relevant Principles as drafted;**
- **Following this process, a new licence condition to apply to DNOs that have not yet submitted a long term methodology for approval;**
- **"Two pots" issue with DG price control to be addressed as part of DPCR5.**

Appendix 1 – Brief overview of the G3 (FCP) Methodology

The G3 methodology is based on the Forward Cost Pricing (FCP) method. It is a holistic method which covers the EHV, HV and LV voltage levels for demand and generation (including generation benefits). SP Energy Networks has recently submitted a modification report to the Authority for implementing the FCP approach. The Modification Report, two consultants' reports testing the methodology, a consultation documents with responses and a workshop's notes can be found in the Scottish Power website:
http://www.scottishpower.com/StructureOfChargesProjectG3.htm

The G3 methodology is a three-stage process:

In the **first stage**, forward-looking FCP rates (£/kVA/annum) for reinforcement of the network are determined by the G3 Forward Cost Pricing (FCP) methodology. For demand, the FCP methodology forecasts future reinforcement using load flow contingency analysis based on the actual configuration of the network, demand data and growth assumptions for EHV, down to the EHV/HV level of the network. These forecasted reinforcements are then converted into the forward-looking costs for these voltage levels, which provide economic locational signals to current and prospective EHV customers. For the High Voltage (HV) and Low Voltage (LV) levels of the network the FCP methodology uses historic reinforcement data to build a forecast of future reinforcement costs. The EHV proportion of costs which is allocated to HV and LV costs is cascaded from the FCP costs on an averaged basis.

The FCP methodology for generation identifies both the generation costs and generation benefits. The costs are determined by performing a fault level and reverse power analysis of the real network, down to the 33/11 kV level. Benefits are calculated in relation to the demand costs that generation would offset.

The FCP approach put forward by G3 is only to consider network reinforcements that are required in the next 10 years. This period is longer than that currently required in the production of the LTDS (5 years), but still sufficiently short to enable robust forecasts to be made. The time period is however, sufficiently long to give cost signals that will enable customers to modify their behaviour and potentially avoid the need for future reinforcement.

The **second stage** of the G3 methodology is the application of the G3 tariff model, which is a direct development from the COG model and the approaches agreed with the other DNOs at the COG group. This model brings together the FCP rates and benefits determined by the FCP methodology in the first stage of the process, and all other relevant costs (such as O&M, refurbishment, NGET Connection (Exit) and Licence costs). It then uses other inputs such as demand and volume data to profile these costs and allocate them to the appropriate customer groups, producing yardstick costs. These yardstick costs are then put together with other costs, such as site-specific sole-use asset costs and scaled to match the target revenue.

From the yardstick costs, the final tariffs are produced in the **third stage** of the process according to a predetermined allocation method

In our view, the G3 approach overcomes the weakness of the LRIC method as implemented by WPD, in that it is able to accommodate local variations in growth rates in a way which gives desirable pricing properties (see figures below).

The following example illustrates the behaviour of the FCP formula under certain scenarios:

Inputs	**Symbol**	**Base Case value**
Cost of reinforcement, £	A	500,000
Capacity at which reinforcement will be required, kVA	C	150,000
Cost recovery period, years	T	10
Discount rate, %	i	6.9%
Demand growth rate, %	G	1%

Table 1: Stylised example of FCP methodology for EHV demand

Source: Frontier Economics

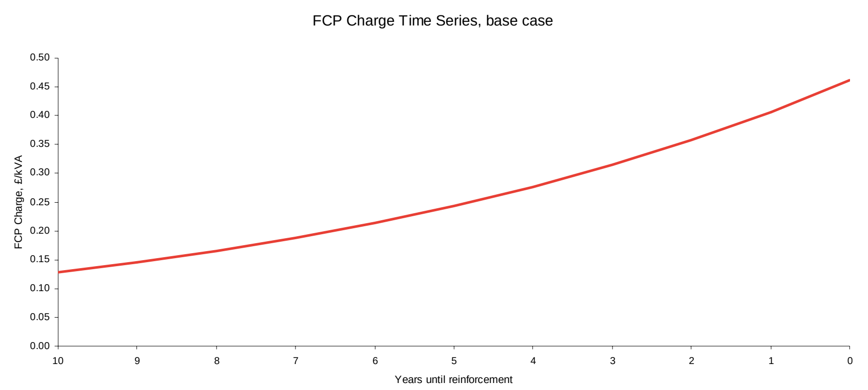

Figure 1: Illustration of time-path for charges under the EHV demand charging formula

Source: Frontier Economics

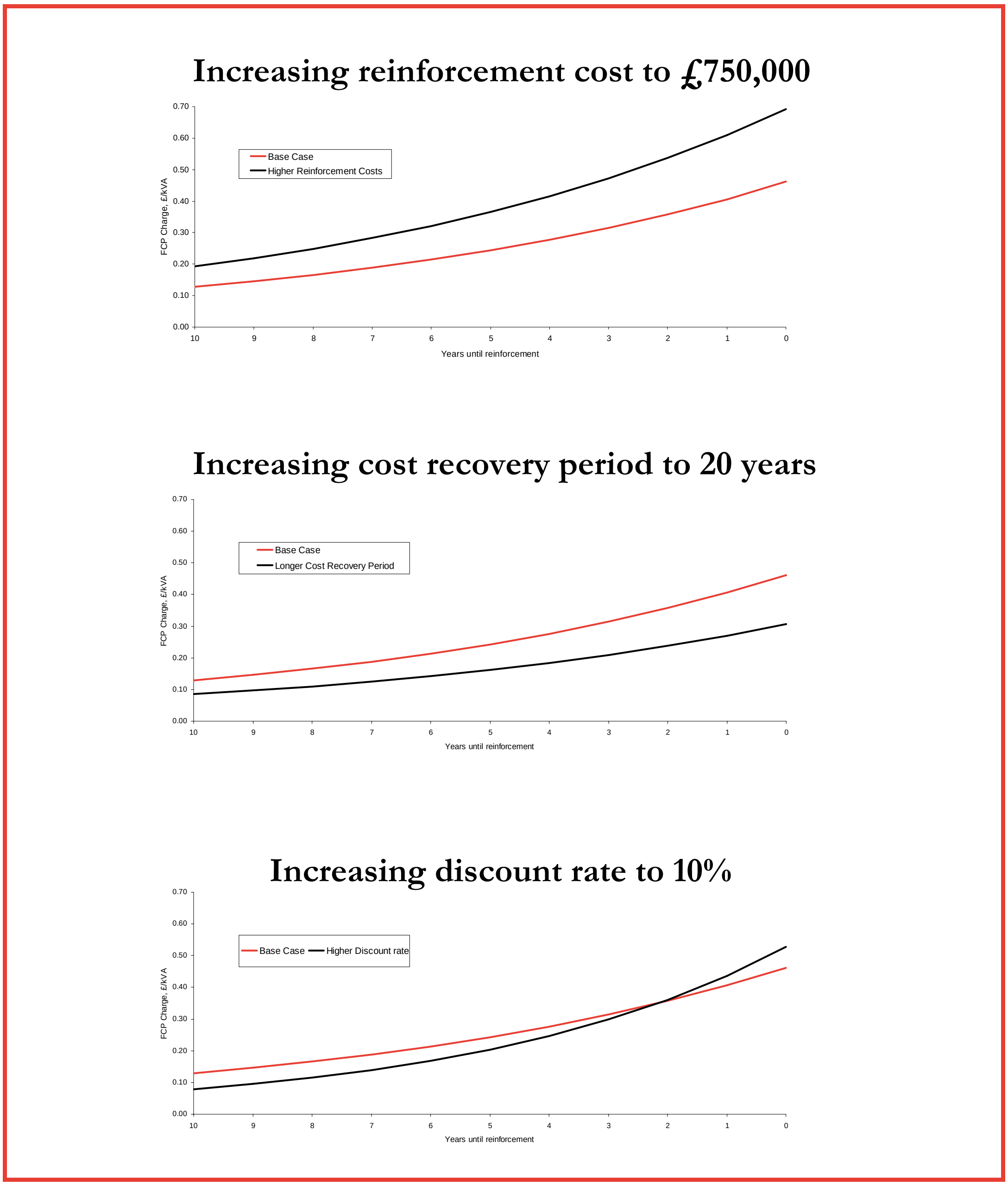

Figure 2: Scenario analysis for EHV demand £/kVA charging formula

Source: Frontier Economics

The figures above demonstrate the desirable properties of the FCP approach, which are:

- If the reinforcement costs doubles then the FCP rate should double, implying a linear variation with reinforcement cost.
- The FCP rate should increase as reinforcement approaches.
- For a given demand, the FCP rate should increase with increasing growth rate to give stronger signals.

- Increasing the discount rate should give lower FCP rates at more distant times prior to reinforcement.
- The decrease of FCP rate with increasing discount rate should be stronger than exp(-*it*).
- As the growth rate tends to zero the FCP rate should tend to zero for all demands less than the capacity at which reinforcement is required.

In terms of cost transparency and cost reflectivity, wherever possible the G3 methodology aims to make use of auditable data such as LTDS, regulatory accounting information and other publicly available data, in order to comply with the principle of transparency. It also makes use of the same company network data that is used for investment planning and regulatory purposes, which ensures consistency.

Appendix 2 - An example of an LRIC charging methodology

A worked example of an LRIC approach is given in an IEEE paper.[1] In this example, the network element for which reinforcement is considered has a capacity of 45MW. As the only form of reinforcement taken into account is duplication, this means that the cost of bringing forward a 45MW investment in order to accommodate demand starting 1MW higher is converted into a price applied to each 1MW of load.

The spreadsheet calculation specified in table 2 follows the specification of the LRIC method given by the paper. This calculation reproduces the results from the worked example as published in the article: see table 3 below.

Table 2 Microsoft Excel formulae to reproduce IEEE paper example of the LRIC method

Variable	*Symbol and formula*	*Value*
Current load (MW)	C2	5
Current capacity (MW)	C3	45
Growth rate	C4	1.60%
Cost of reinforcement	C5	£ 3,193,400
Discount rate	C6	6.90%
Current years to reinforcement	C7=LN(C3/C2)/LN(1+C4)	138.4
NPV of reinforcement costs	C8=C5/(1+C6)^C7	£ 311
Load assuming an additional 1MW	C9=C2+1	6
Years to reinforcement assuming an additional 1MW	C10=LN(C3/C9)/LN(1+C4)	126.9
NPV of reinforcement costs assuming an additional 1MW	C11=C5/(1+C6)^C10	£ 670
Change in NPV of reinforcement costs due to additional 1MW	C12=C11-C8	£ 359
Convert into a 40-year annuity starting now (£/MW/year)	C13=PMT(C6,40,-C12)	£ 26.6

Table 3 Results from reproduction of IEEE paper example of the LRIC method

Current load (MW)	*Charge (£/MW/year)*
5	£ 26.6
10	£ 209.5
20	£ 1,783.0
30	£ 6,364.0
40	£ 15,783.3
44	£ 21,341.4
45	£ 22,916.0

Source for tables 2 and 3: Reckon LLP re- implementation of worked example in Li, Furong and Tolley, David L (2007) Long-run Incremental Cost — Pricing Based on Unused Capacity.

[1] Li, Furong and Tolley, David L (2007) Long-run Incremental Cost — Pricing Based on Unused Capacity, preprint of IEEE Transactions on Power Systems, Volume 22, Issue 4, pages 1683–1689.

SP ENERGY NETWORKS

The charges calculated by this method can be sensitive to the assumed growth rate. Using the same values as above for the other parameters, table 4 illustrates this sensitivity in three cases: a part-loaded circuit (30MW used out of 45MW), a well-loaded circuit (40MW) and a nearly fully loaded circuit (44MW).

Table 4 Sensitivity of LRIC method to demand growth assumption

Demand growth assumption	*Charge (£/MW/year) (initial load 30MW)*	*Charge (£/MW/year) (initial load 40MW)*	*Charge (£/MW/year) (initial load 44MW)*
0.10%	£ 0.0	£ 382.5	£ 183,941.7
0.20%	£ 0.6	£ 5,937.5	£ 124,975.6
0.40%	£ 196.9	£ 16,892.0	£ 74,137.1
0.80%	£ 2,508.4	£ 20,282.7	£ 40,612.6
1.60%	£ 6,364.0	£ 15,783.3	£ 21,341.4
3.20%	£ 7,214.2	£ 9,906.3	£ 11,006.6
6.40%	£ 5,495.0	£ 5,614.0	£ 5,654.1

Source: Reckon LLP calculations using LRIC method applied to several possible demand growth assumptions.

The figure for 0.1 per cent annual growth and a current load of 44MW is particularly extreme: it implies a total income from customers of more than £8 million a year (44MW*£183,941.7/MW), when the only network investment planned is a £3.2 million reinforcement that would accommodate load growth for the next 716 years (log(90MW/44MW)/log(1.001)).

In the extreme limit of a zero growth rate, using figures from the above worked example, this method would imply that:

a) An increment added to a nearly fully loaded network element would bear the whole cost of the reinforcement it would cause (if the charges were maintained over the 40-year annuity period), because it would be deemed to bring the estimated time to reinforcement from the very distant future to now, so that the net present value of reinforcement costs increases from almost nothing to the full cost of the reinforcement.

b) In all other cases, the charge is negligible, as the estimated time to reinforcement would be very long whether or not the increment is included.

For a load that is a main user of the reinforcement, the actual incremental cost of reinforcement that it causes would be at most the total cost of the reinforcement, but the charge determined by a marginal cost estimation method could be much higher. For example, using the figures from the IEEE paper's worked example (tables 3 and 4 above), a 45MW new load added to a 44MW existing load would only cause £3,193,400 of capital expenditure, whereas it would incur a locational charge of £960,363 a year (45*21,341.4), derived by annuitising a marginal cost of about £37 million — wholly out of proportion with the incremental capital expenditure caused by the relevant load.

A third possible deviation from the aim of facing customers with cost-reflective incentives arises from the use of a 40-year annuity to convert the estimated capital expenditure into an annual use of system charge. In cases where the time to reinforcement is longer than 40 years (likely to be an issue if growth rates are low), this could lead to excessive costs being imposed on load as they would be paying the charge based on the 40-year annuity for longer than 40 years. In cases where the time to reinforcement is short, there is a possibility that the incentive could be lower than the relevant incremental cost, as in some cases the charge calculated by this method would drop dramatically immediately after the reinforcement is delivered. This effect might offset the discrepancy between incremental and marginal cost noted above in the case of a larger load, but there is no guarantee that it would do so — indeed in the case of a 45MW load added to the 44MW scenario in the IEEE paper the charges after reinforcement would be higher as a further reinforcement would then be planned for the short term.

A further implication of the features reviewed above is that the prices produced by this LRIC method depend significantly on the assumptions made about the demand growth rate and the lumpiness of investments.