CE Electric UK

Revised use of system charging methodology for NEDL and YEDL from 1 November 2006 – proposal document

Modification number: 0002/2006

Contents

1 Executive summary

This proposal document presents the revised use of system (UoS) charging methodology that CE Electric UK (CE) intends to implement in both Northern Electric Distribution Limited (NEDL) and Yorkshire Electricity Distribution plc (YEDL) from 1 November 2006. It provides supporting evidence including impact and sensitivity analysis; illustrative charges; details of why this approach better meets our licence requirements and how it provides a firm basis for the removal of the conditions on our methodology.

1.1 Background

NEDL and YEDL currently have conditions attached to Ofgem's approval of their use of system (UoS) charging methodology statements. The Authority's conditions require that CE should progress with urgency the development of a revised charging model based around the comments and views provided in the Authority's letter to ensure that any revised model achieves the relevant objectives to develop and implement a new charging model by 1 April 2007.

1.2 The existing approach

The existing methodology employed by CE for the NEDL and YEDL distribution licence areas, (approved subject to conditions) adjusts the previous year's tariff for volume changes in the customer base, consumption patterns and then for changes in the permitted revenue recovery under the price control. Tariffs for individual customer classes are scaled uniformly to reconcile the revenue with the target income. An obvious weakness with this approach it that it implicitly assumes that the tariff for the previous year, which becomes the basis for charges in the subsequent year, is reflective of the underlying costs.

1.3 The new proposal

Our new proposal for charging low voltage (LV) and high voltage (HV) connected customers is based on the long-run marginal costs of the network and the operating costs identified from our annual price control review submissions to Ofgem. The implementation is based on distribution reinforcement model (DRM) principles, founded on a reference 500MW network based on the topography and demographics of our existing network. This representative network reflects the manner in which the NEDL and YEDL systems are likely to develop in future and hence is not based on any specific part of out current network but is a representation of how we might build a future network. - There are two different network models, one for YEDL and one for NEDL, which will result different yardstick values for each network. The basic principle of the model is to share the asset costs of the network between customers by reference to their contribution to the demand that necessitates the assets (based on system peaks). The outputs from the model are cost per kW (or kVA) of maximum demand at each voltage and transformation level (cost yardsticks). This approach ensures that the tariffs are based on our view of future costs and will bring us into line with the methodologies that are currently approved for other DNOs.

We have carefully researched the basis of the DRM as originally proposed by the Electricity Council[1] and subsequently developed by EA Technology[2]. This has revealed that some of the practices in the DRM were founded on policy objectives or market arrangements that may no longer be wholly appropriate. Our development of a DRM to apply in the NEDL and YEDL areas provides an opportunity to bring it into line with current market practices. (Implementation of the model is via a newly developed Microsoft Excel spreadsheet designed to clearly and logically display the inputs, calculations and outputs).

1.4 Why our proposal better meets the licence requirements

We believe that our new methodology better meets the licence conditions in the following areas:

- It represents an equitable and cost-reflective mechanism for allocating costs in order to set tariffs;
- It is based on forward-looking costs and as such ensures that our costs are reflected back to customer groups based on the costs they themselves generate;
- It is relatively simple and transparent and should be easily understood by our customers as it is founded on the same principles as methodologies already approved by the Authority for a number of other DNOs.
- It uses asset-based yardsticks (based on modern equivalent asset (MEA) prices and technologies) as its prime cost driver, which is regarded as the most representative means of allocating potential future network cost to different customer groups;
- It uses operating costs that are based on audited regulatory reporting pack data and allocates these on both an asset and customer basis, dependent on the nature of the cost;
- It addresses apparent anomalies in the application of the DRM model.
- As this is a long-run cost model the approach has the potential to be part of the enduring solution, particularly for customers connected at lower voltages; and
- In addition to addressing Ofgem's concerns, we believe the changes also better meet other relevant licence objectives, principally by increasing cost-reflectivity and

[1] Tariff Formulation Manual, Second edition. The Electricity Council Commercial Department June 1984

facilitating competition due to the greater transparency and understanding of the proposed approach.

1.5 External validation of our approach

In order to obtain an independent view of the work we have undertaken and to facilitate the removal of conditions on our UoS charging methodology, we employed external consultants to review and validate our new pricing model.

David Tolley, from DLT Consulting, was approached as he has a wealth of relevant industry experience and has detailed knowledge in the charging arena. He provided an independent report, attached in **appendix 7**, of his assessment of our proposed approach. The report provided 9 recommendations for possible builds on the current model – all of which have been considered and 8 implemented.

1.6 Impact of implementing the model

This proposal document contains a comprehensive impact and sensitivity analysis along with illustrative tariffs. All have been calculated based on the same forecast information that was used to calculate our current 2006/07 charges and ensure that the illustrative charges recover the same amount of income. Hence, the impact and sensitivity analysis is on a like-for-like basis, so should make comparison easier.

At the highest level the results of implementing the new methodology shows a general movement in income recovery away from high voltage (HV) connected customers towards those connected at lower voltages (LV). The table below details the movement in income recovery between voltage levels - it should be noted that extra high voltage (EHV) income remains unchanged as we have not changed the methodology for these customers.

Voltage	NEDL	YEDL
Low voltage (LV)	2%	4%
High voltage (HV)	(16%)	(19%)
Extra high voltage (EHV)	0%	0%

The reduction in the amount of income recovered from HV connected customers is the same as the increase to LV connected customers due to the fact that allowed income remains unchanged. The reason for the larger percentage change for HV customers is the because of this groups smaller relative size.

[2] Cost allocation in distribution monopolies – turning theory into practice EA Technology report N^{o} 90607 November 1998

1.7 Conclusions

Given the information above, we believe that this proposal meets our licence obligations and the evidence in this report provides a firm basis for the removal of the conditions on our methodology.

2 Background

Northern Electric Distribution Limited (NEDL) and Yorkshire Electricity Distribution plc (YEDL) currently have conditions attached to Ofgem's approval of their use of system (UoS) charging methodology statements. These are that:

- CE should progress with urgency the development of a revised charging model based around the comments and views provided in the Authority's letter, dated 20 December 2005[3], to ensure that any revised model achieves the relevant objectives;
- Due to the extension of timescales for completion of this condition CE should also consider other developments in the industry, such as the studies into electricity distribution charging models during the course of this year, when considering a revised model; and
- CE should develop a revised UoS charging model to be approved and in place by 1 April 2007.

Charges applicable from 1 April 2006 were set using the current approach, which is published on our website. Since the publication of these charges we have been working with Ofgem to review and develop an alternative approach to our demand UoS charging methodology, as required by the Authority.

This document details our proposed methodology for calculating LV and HV demand charges which, if approved, will require the re-writing of section 3 "Methodology for calculating general LV and HV demand charges" of our existing methodology statements. (the proposed wording is contained in **appendix 7**).

2.1 Licence requirements

Licence requirements, as of 1 April 2005, are that DNOs' methodologies must be reviewed at least annually and modifications (if any) should only be introduced as necessary for the purpose of better achieving the relevant objectives set out in SLC4 (3). For the purpose of the methodology, the relevant objectives are:

a) that compliance with the use of system charging methodology facilitates the discharge by the licensee of the obligations imposed on it under the Act and by this licence;

[3] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/13349_CE_NEDL_201205_charging_model_decision_letter.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/distributioncharges/edc2
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/13348_CE_YEDL_201205_charging_model_decision_letter.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/distributioncharges/edc2

b) that compliance with the use of system charging methodology facilitates competition in the generation and supply of electricity, and does not restrict, distort or prevent competition in the transmission or distribution of electricity;

c) that compliance with the use of system charging methodology results in charges which reflect, as far as is reasonably practicable (taking account of implementation costs), the costs incurred by the licensee in its distribution business; and

d) that, so far as is consistent with sub-paragraphs (a), (b) and (c), the use of system charging methodology, as far as is reasonably practicable, properly takes account of developments in the licensee's distribution business.

2.2 The aims of tariffs

In addition to the licence requirements detailed above CE aims to set tariffs which:

- give consumers 'messages' about the cost their consumption patterns impose on the network; and
- Are fair between one user and another.
- bring in the correct level of allowed revenue;
- have simple tariff structures, which are as stable as possible;

3 Detailed description of the proposals

The mechanism used for calculating UoS charges is a two-stage process.

- The first stage is to use the pricing model to determine yardstick tariffs, daily fixed charge (p/cust/day), a single unit rate charge (p/kWh) and a capacity charge (p/kVA/day) for the ten main customer groups into which our tariffs can be allocated, namely:
    - CG1 - Domestic unrestricted (PC1);
    - CG2 - Domestic restricted (PC2);
    - CG3 - Non-domestic unrestricted (PC3);
    - CG4 - Non-domestic restricted (PC4);
    - CG5 - Large NHH LV (PC5-8);
    - CG6 - Large NHH HV (PC5-8);
    - CG7 - HH LV;
    - CG8 - HH HV;
    - CG9 - UMS; and
    - CG10 - EHV.
- The second stage is to decide whether or not it is appropriate to send any time-of-day signals within these charges in order to encourage the more efficient use of our network, which could potentially defer the requirement for network reinforcement.

The new CE pricing model for low voltage (LV) and high voltage (HV) connected customers is based on the long-run marginal costs of the network and the operating costs identified from our annual price control review information submissions to Ofgem. The model is a customised version of the EA Technology cost allocation spreadsheet developed in the late 1990s and adopts the same principles as those used in the original Electricity Council distribution reinforcement model (DRM) developed in the 1980s. Implementation of the model is via a newly developed Microsoft Excel spreadsheet designed to clearly and logically display the inputs, calculations and outputs.

There is a substantial level of common costs involved in providing a distribution network, and a method is needed for the equitable attribution of costs between different groups of customers. To date, it has been generally accepted within the industry that the most appropriate way to allocate costs for tariff setting is to use the long-run marginal cost, which provides an economically efficient and relatively stable pricing structure. The proposed methodology is designed to calculate cost-reflective tariffs via a model that utilises:-

- A representative replacement network utilising both modern equivalent asset (MEA) prices and modern technologies;
- Settlement data and volume forecasts; and
- The costs of serving customers that are not dependent on the network investment (generally operating costs), which are typically allocated to the fixed charge – the model uses annual price control review information submissions since this is believed to offer a reasonable approximation to the long-run marginal cost for this element and the data is readily available.

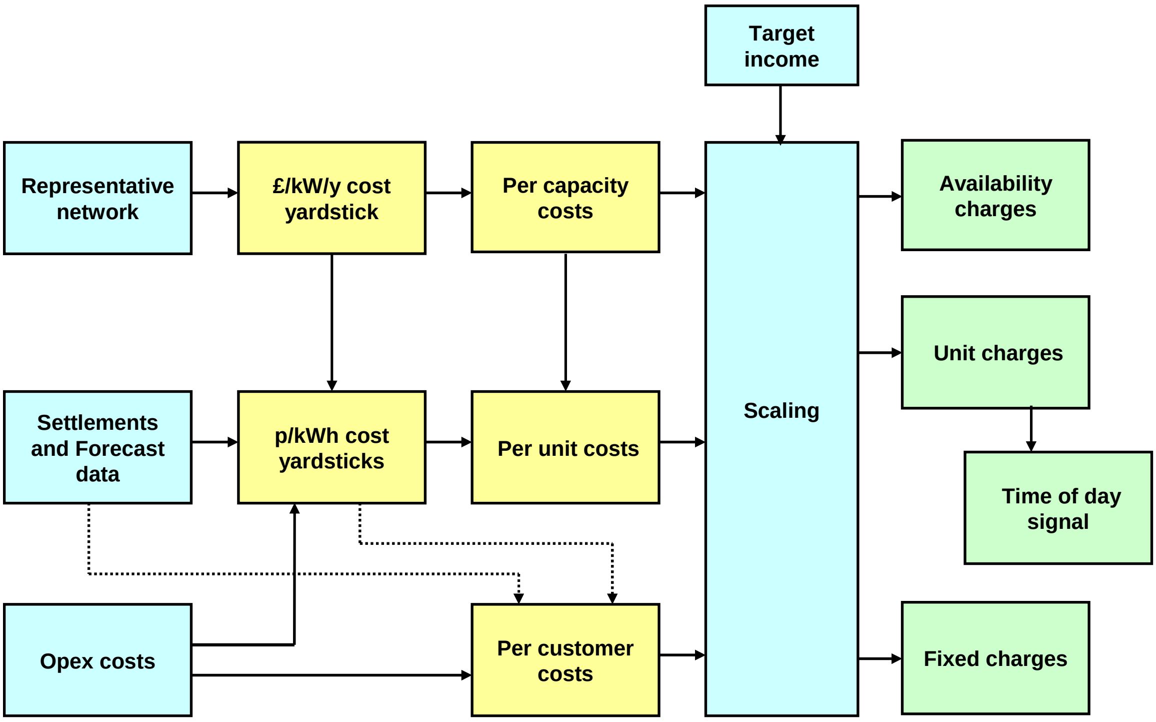
The basic principle of the model is to share the asset costs of the network between customers by reference to their contribution to the demand that necessitates the assets. The outputs from the model are cost per kW (or kVA) of maximum demand at each voltage and transformation level[4] (cost yardsticks), detailed below.

- 132 kV network;
- 132kV / 33kV Substations;
- 33 kV Circuits;
- 33kV / 11kV Substations;
- 11 kV Circuits;
- 11 kV / LV Substations; and
- LV Circuits.

These are then used to derive yardstick unit and availability charges that can be used in conjunction with the standing charge element. The outputs can then be scaled to create tariffs that will recover specified allowed revenues.

The following figure shows a high-level overview of the end-to-end process.

[4] our tariff structure assumes that: connections at 6, 11 and 20 kV attract the same costs; and that connections supported other than by the standard MITS/132/33/11/LV route attract the same cost as the conventional equivalent (eg the Tynedale 275/20 kV system)



The key references that that have been used to build and develop the new pricing model are:

- The Tariff Formulation Manual produced by the Electricity Council (June 1984).
- EA Technology Report no 4700: "Cost allocation in distributed monopolies – turning theory into practice" by R M Smith (November 1998);
- EACASS v1.1 – The EA Technology Cost Allocation Spreadsheet "Manual" produced in the late 1990s; and
- Feedback from our external consultants, DLT Consulting, who reviewed, validated and critiqued our proposal.

Our aim is to achieve a set of tariffs that are both clear and cost-reflective and as such will facilitate competition in the supply of electricity. They will also be based on the same principles as those of other DNOs, and furthermore will enable us to make a cleaner transition to the longer-term framework in due course.

The three main areas of inputs into the model are discussed below:

3.1 Asset information

The pricing model calculates the cost of building and maintaining the plant and equipment necessary to meet an extension to the current system of 500MW of maximum demand at each voltage level. From this information annualised yardstick costs (p/kW) are derived for each voltage and transformation level of the network.

- **The network model** - the model utilises a representative network, based heavily on the topography and demographics of our existing networks, but is not a literal representation of this network. Rather, it represents the way in which we would provide a network to meet the requirements of typical demands and topography if we were to build it today using the latest equipment, technologies and network design standards. We have two different representative models, one for NEDL and one for YEDL. (It should be noted that the representative network only includes those assets that would be paid for by CE Electric UK and excludes those that would, under current connection policy, be paid for via connection charges – this avoids any potential double counting of income recovery[5]). It is also assumed that this demand comes from a hypothetical new 'greenfield' development that has no investment implications for the rest of the network.

- **Calculation of annualised costs** – the annualised costs are calculated based on 6.9% rate of return and a twenty year depreciation period. The reason for using a twenty-year depreciation period rather than a more typical asset life value of forty years is to reflect the decline in earnings power of the representative network assets as new technologies are developed. This also brings the depreciation period into line with the regulatory treatment of assets.

  Much of the debate on depreciation period is academic, because the higher annualised costs that result from the use of a smaller depreciation period means that a smaller scaling factor is required to achieve allowed income. Whereas, using a larger depreciation period results in a lower annualised charge and a greater revenue reconciliation requirement. There is no material (less than 0.5%) variance in the distribution of income recovery that results from either approach.

3.2 Settlements and forecast information

After derivation of the annualised yardstick costs for each voltage and transformation level of the network, via the asset information, these costs are then allocated to the different customer tariff groups. This enables the production of meaningful unit yardstick costs, or pence per kWh costs, for each tariff group.

It is an engineering reality that the level of system maximum demand dictates the amount of investment that is required in the distribution system. Therefore, the pricing model allocates costs to those customers using the network at that time (i.e. costs are allocated to customers according to their contribution to the level of system maximum demand).

[5] Overall, double recovery is avoided by deducting customer contributions from gross investment in calculating the RAV. Here, the adjustment maintains the appropriate balance of cost incidence in the model

In order to calculate the contribution of each tariff group to system maximum demand, a large amount of, up-to-date, actual and forecast information is required.

- **Forecast information** – The latest volume forecasts of units distributed, customer numbers and customer agreed capacities are required – for consistency and to allow like-for-like comparisons all forecasts used in the calculation of the illustrative charges in this paper are the same as were used for the calculation of the current 2006/07 charges; and
- **Settlements information** – The majority of this information is based on billing system outputs. It is relatively easy to obtain this information for customers who are metered on a half-hourly (HH) basis, but not so for non-half hourly (NHH) metered customers whose data is profiled and subject to various different reconciliation runs. Our model works on actual HH consumption and the latest available reconciliation of NHH data.

  From the settlements data coincidence factors to system peak, load factors (i.e. kWh/y/kW) and system losses can be calculated for each tariff or customer group.

3.3 OPEX costs

The model uses the annual price control review information submissions to Ofgem, since for these repetitive and generally stable activities, short-run costs are effectively the same as long-run marginal cost.

The opex costs are categorised into three areas (direct activities, indirect activities and non-activity based costs), the majority of which are recovered on a pence per day basis so that the cost can easily be identified and quantified. The exception being exit charges which in line with normal DRM practice is recovered on a p/kWh basis. The list below gives more detail on how the operating costs are treated:

- Exit charges – built into the p/kWh yardsticks on a pro rata basis in relation to the amount of capacity utilised by each customer group (i.e. the calculated SMD including losses);
- Asset-related opex – built into the p/day yardsticks on a pro rata basis in relation to the outputs of the representative network model (i.e. on a capacity basis in relation to the asset-generated p/kWh yardstick cost values); and
- Non-asset related opex – also built into the p/day yardsticks, only this time on a customer numbers basis.

Consideration has been given as to whether or not to include all annual operating costs in the model or just a subset of the cost that could be deemed to relate to the representative network. After careful deliberation we decided that our proposed approach (to include all operating costs) was most appropriate as it reduced the amount of scaling required at the back end of the process. Again as with the depreciation issue, scenario analysis showed that there is no material variance in the distribution of income recovery that results from either approach.

4 Why our proposal better meets the licence requirements

The Authority's conditional approval requires that CE should progress with urgency the development of a revised charging model based around the comments and views provided in the Authority's letter to ensure that any revised model achieves the relevant objectives to develop and implement a new charging model by 1 April 2007.

Our proposals address these concerns by replacing the current approach, which starts from the assumption that existing charges are cost-reflective (without actually providing evidence of this), with a methodology based on long-run marginal costs and implementing this (if approved) by 1 November 2006.

We believe that our new methodology better meets the licence conditions in the following areas:

- It is based on forward-looking costs and as such ensures that costs are reflected back to customer groups based on the cost they generate;
- It represents an equitable and cost-reflective mechanism for allocating costs in order to set tariffs;
- It is relatively simple and transparent and should be easily understood by our customers as it is founded on the same principles as methodologies already approved by the Authority for a number of other DNOs;
- It addresses apparent anomalies in the application of the DRM model.
- It uses asset-based yardsticks (based on MEA prices and technologies) as its prime cost driver, which is regarded as the most representative means of allocating potential future network cost to different customer groups;
- It uses opex costs that are based on audited regulatory reporting pack data and allocates these on both an asset and customer basis, dependent on the nature of the cost;
- As this is a long-run cost model the approach has the potential to be part of the enduring solution, particularly for customers connected at lower voltages; and
- In addition to covering off the condition we believe the changes also better meet relevant licence objectives, principally by increasing cost-reflectivity and facilitating competition due to the greater transparency and understanding of the proposed approach.

5 External validation of our approach

In order to obtain an independent view of the work we have undertaken, to facilitate the removal of conditions on our UoS charging methodology, we decided to employ external consultants to review and validate our new pricing model.

We approached David Tolley, from DLT Consulting, as he has a wealth of relevant industry experience and has detailed knowledge in the charging arena, specifically:

- He is an active member of the Ofgem structure of charges implementation steering group (ISG);
- He was involved in the Bath University work that was initiated by Ofgem; and
- He was recently employed by the Energy Networks Association (ENA) to undertake a review of alternative cost attribution methodologies.

We do not believe that any other consultancy companies could boast these skills to the level of adequacy required and, as such, David was appointed to review and critique the development of our distribution reinforcement-type model (DRM) to set UoS charges that would apply to LV and HV connected customers. He spent two days at our Castleford offices at the end of June interrogating our models and understanding the rationale behind them and the research we have undertaken.

DLT Consulting has provided an independent report on its assessment of our proposed approach. The full report is attached in **appendix 1** to this document, but a summary of the conclusions and recommendations is presented below:

- "*…The tariff model currently in use by CE-Electric adjusts the previous year's tariff for volume changes in the customer base, and then for changes in the permitted revenue recovery under the price control. Tariffs for individual customer classes are scaled uniformly to reconcile the revenue with the target. An obvious weakness with this approach is that it implicitly assumes that the tariff for the previous year, which becomes the basis for charges in the subsequent year, is reflective of the underlying costs*."
- "*…In moving to a DRM founded on a reference 500 MW network that reflects the manner in which the NEDL and YEDL systems are likely to develop CE is looking to ensure that the tariff is based on its underlying costs...*"
- "*…CE Electric has carefully and comprehensively researched the basis of the DRM as originally proposed by the Electricity Council and subsequently developed by EA Technology…*";

- "*…In doing so CE have revealed that some of the practices in the DRM were founded on policy objectives or market arrangements that may no longer be wholly appropriate…*";
- "*…Their development of a DRM to apply in the NEDL and YEDL areas provides an opportunity to bring the DRM into line with current market practices…*";
- "*…CE's model was still under development when this review was undertaken. Consequently any proposals made at this stage should be seen as being part of the overall development of an appropriate model…*"; and
- The report provides 9 recommendations for possible builds on the current model – all of which have been considered and 8 implemented.

The table below details the recommendations and the action taken

Recommendations		**Action**
1	Assess whether the Diversity Allowances in the original EA model are appropriate for the NEDL and YEDL networks	Implemented – We believe the EA diversity allowances are appropriate
2	Consider using an annuity factor of 9.37% instead of 7.41% to calculate the annualised costs of the 500 MW network model	Implemented
3	Identify those operational costs that relate to assets and allocate them on the basis of asset costs derived from the full network model rather than the DRM	Implemented
4	Allocate rates in accordance with the assets incorporated in the 500 MW DRM	Implemented
5	Discard the customer weighting factors from the model since these relate mainly to metering costs, and consider replacing them with an algorithm that better reflects the billing costs of central systems	Implemented
6	Consider whether it is appropriate to continue to use coincidence factors in the calculation of the availability charge and, if so, whether they should reflect the characteristics of the present-day NEDL and YEDL customer demands	Implemented
7	Rationalise the relationship between the calculation of the availability charge and the determination of connection charges	Implemented
8	Exclude LV service cable costs from the DRM asset base to the extent that they are recovered by connection charges, but again rationalise how these costs mesh with the connection charge policy	Implemented
9	Include, at least in principle, a working capital component in the yardstick calculation, always assuming that there is an associated cost	Not implemented – Development for long-term consideration

6 Consultation/communication process carried out to date

CE has consulted with its suppliers, large end-users and industry stakeholders throughout the development of these proposals. The following details the consultation/communication processes that we have followed:

- 03 February 2006 – Director's letter to Ofgem with regard to the Authority decision letter of 20 December 2005, requesting an opportunity to meet to discuss this matter further.
- 16 February 2006 – Director-level meeting with Ofgem to discuss the conditions placed on the CE use of system charging methodologies.
- 28 February 2006 – Follow-up letter to the Ofgem meeting held on 16 February 2006.
- 30 March 2006 – Working-level meeting with Ofgem to:
    - Better understand Ofgem's reason for conditionally approving CE Electric's use of system charging methodologies;
    - Discuss initial thoughts on the way forward for CE Electric's methodology;
    - Share our plans and the anticipated timeline for delivery; and
    - Agree that the proposals are fit for purpose and that they meet the requirements to get the conditions on our methodology removed.
- 04 April 2006 – Follow-up letter to the Ofgem meeting held on 30 March 2006.
- 01 May 2006 - DLT consulting approached to undertake an independent review and critique of our proposed approach.
- 26 May 2006 – Consultation letter 'Development of CE Electric UK charging methodologies' sent to suppliers, large end-users, Ofgem and ISG members detailing our plans to change the way we calculate the use of system (UoS) charges. The letter requested feedback and comments on the proposed changes. (Closing date for responses 09 June 2006).
- 30 May 2006 - DLT Consulting appointed.
- 21/22 June 2006 – DLT Consulting visit Castleford to interrogate our models and understand the rationale behind them and the research we have undertaken.
- 30 June 2006 – Draft report received from DLT Consulting
- 05 July 2006 – Working-level meeting with Ofgem to:
    - Provide an update on progress since the last meeting;

    - Give an overview of the CE pricing model;
    - Share some of the initial sensitivity and impact assessment (although still work in progress);
    - Detail the proposed next steps:
    - Share our communication plan; and
    - Provide feedback form the ‘Development of CE Electric UK charging methodologies’ letter sent to suppliers/EHV customers on 26 May 2006.
- 07 July 2006 – Follow-up letter to the Ofgem meeting held on 05 July 2006.
- 14 July 2006 – Final report received from DLT consulting.
- 18 July 2006 – Presented overview of the structure of the model to the ISG
- 23 August 2006 – Working-level meeting with Ofgem to:
    - Discuss the draft proposal document;
    - Agree amendments that need to be made to the document; and
    - Agree timetable for submission of the formal proposals document.
- 25 August 2006 - Follow-up letter to the Ofgem meeting held on 23 August 2006.
- 6 September – An early indication was given to Ofgem of the impact and sensitivity analysis that was likely to be included in the final proposals document.

To build on this the following further steps are planned;

- Early September 2006 – Submission of revised use of system methodology for NEDL and YEDL – proposal document (including impact and sensitivity analysis). A copy of this will also be sent to suppliers and large end-users.
- 2 November 2006 - Hold seminar/workshop for suppliers and large end users within our area to explain the methodology. (Current thoughts are that this should be an annual seminar – to provide an early indication of potential changes, prior to indicative charges)
- Late December - Publish indicative changes; and
- Adhoc one-to-one meetings with suppliers and large end users as requested.

In addition to the above we have actively participated and considered developments suggested at the implementation steering group (ISG), chaired by Ofgem, and the ENA structure of charges working group, where all DNOs have been working collaboratively to develop the enduring charging arrangements.

6.1 Feedback from the consultation letter and ISG

As stated above at the end of May 2006 our intentions were flagged to suppliers, large end-users, Ofgem and ISG members in a consultation letter ‘Development of CE Electric UK charging methodologies’, which requested comments and feedback. A copy of the letter can be found in **appendix 2**. We also presented our then current findings and proposals at the ISG.

- Formal responses - no formal written responses were received to this letter or presentation;
- Informal responses from suppliers – we received one telephone call from a supplier who was interested in getting a better understanding of the wider structure of charges debate.
- Informal responses from large end-users – we received three telephone calls from large end-users which are detailed below:
    - Although one of their sites is currently enjoying transitional relief they were more interested in getting further background on the wider structure of charges debate and were generally comfortable with the information provided to them;
    - Although this site is not currently enjoying transitional relief they were asking questions about the way their charges are calculated;
    - The end user most adversely affected by the proposal (multiple sites in NEDL and YEDL). Although the YEDL charges are due to increase their main concern was the increases in NEDL. We are currently validating the treatment of the assets driving the price increases.

As can be seen from the above, no formal or informal comments were received with regard to the proposed change to the way we calculate charges for demand customers connected at LV and HV. Hence, this was taken as an indication that the proposals outlined were broadly acceptable to suppliers and large end-users. We also listened to what key stakeholders were saying in forums such as the Implementation Steering Group (ISG) and COG/ENA public workshops. Again these views did not appear to conflict with anything that we were proposing to do.

7 Impact of implementing the model

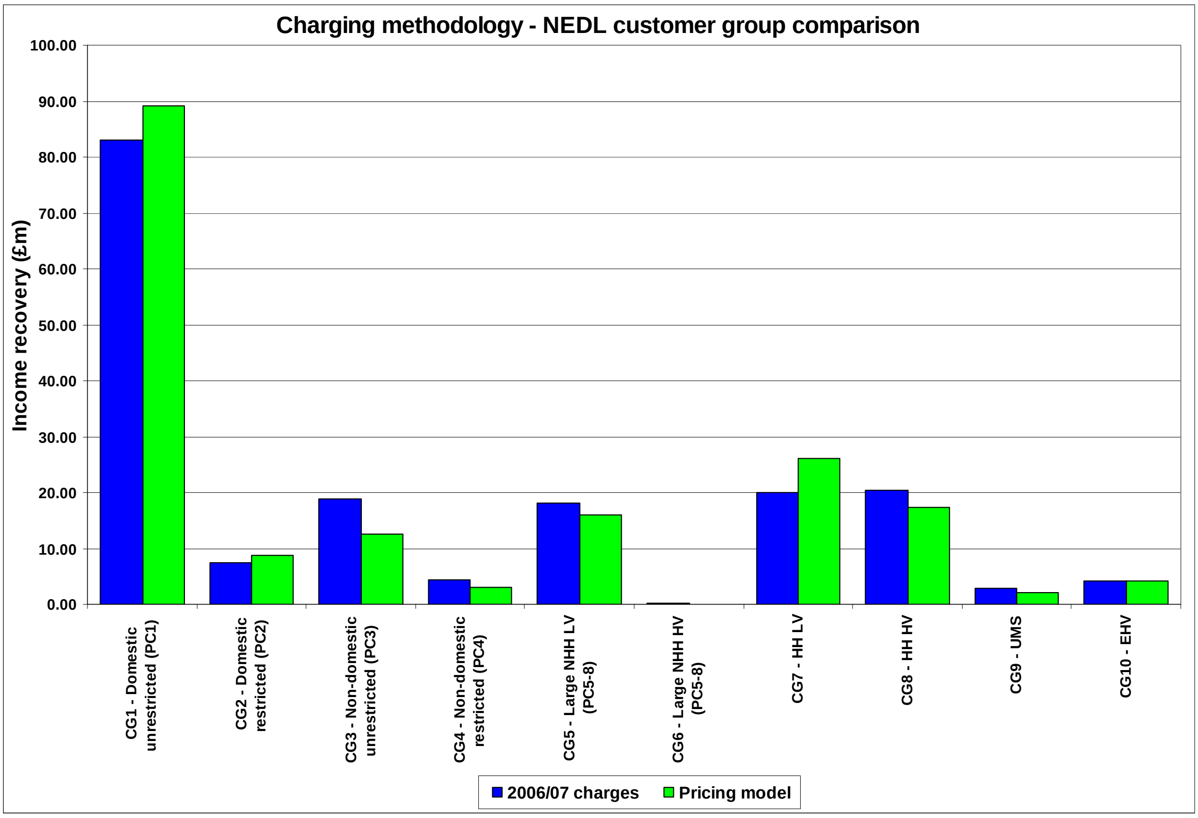
The following section details the output of the comprehensive impact and sensitivity analysis that has been undertaken. It should be noted that the following analysis is based on the same forecast information that was used to calculate existing 2006/07 charges as well as ensuring that the illustrative charges recover the same amount of income. Hence, the impact and sensitivity analysis is on a like-for-like basis, so should make comparison easier.

The trends seen in NEDL and YEDL are different, particularly for half-hourly connected customers, even though identical principles and calculations have been applied. This is more to do with the historical position in which we find ourselves, rather than with any underlying issues with the new models.

The following sections discuss the impact on income recovery, illustrative tariffs and average UoS charges in both NEDL and YEDL.

7.1 NEDL - income recovery comparison

The impact on annual income recovery of implementing the new methodology, in NEDL, on the aforementioned customer groupings is shown in the chart below.



The movement in income recovery can be expressed in terms of the actual movement or the percentage movement from the currently published 2006/07 charges. The table below displays the absolute and percentage movements, for each customer group.

Customer group	2006/07 charges group costs (£m)	Pricing model group costs (£m)	Variance (£m)	% Variance
CG1 - Domestic unrestricted (PC1)	83.07	89.2	6.13	7%
CG2 - Domestic restricted (PC2)	7.50	8.75	1.24	17%
CG3 – Non-domestic unrestricted (PC3)	18.85	12.48	-6.38	-34%
CG4 – Non-domestic restricted (PC4)	4.36	3.13	-1.23	-28%
CG5 - Large NHH LV (PC5-8)	18.05	15.97	-2.07	-11%
CG6 - Large NHH HV (PC5-8)	0.12	0.05	-0.07	-57%
CG7 - HH LV	19.91	26.07	6.17	31%
CG8 - HH HV	20.47	17.31	-3.17	-15%
CG9 - UMS	2.77	2.14	-0.62	-22%
CG10 - EHV	4.24	4.24	0.00	0%
Total	**179.34**	**179.34**	**0.00**	**0%**

The existing methodology employed by CE adjusts the previous year's tariff for volume forecast changes (unit, fixed and availability) and then for changes in the permitted revenue recovery under the price control. This approach implicitly assumes that the tariffs for the previous year are reflective of the underlying costs.

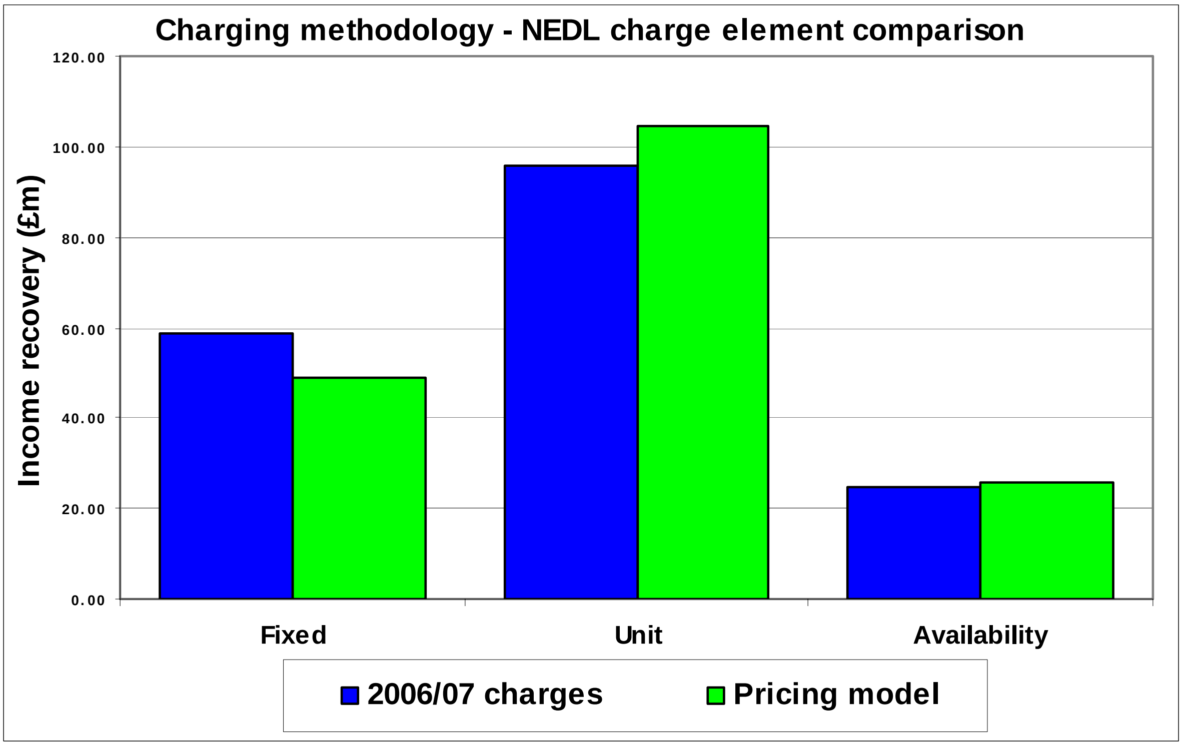
Our new proposal is based on the long-run marginal costs of the network and the operating costs identified from our regulatory reporting packs (RRP). The implementation is based on distribution reinforcement model (DRM) principles, founded on a reference 500MW network that reflects the manner in which the NEDL and YEDL systems are likely to develop and recent settlements data. Hence, this ensures that the tariffs are based on our view of future costs which we believe results in a more cost-reflective recovery of income.

As can be seen in the table above the change in methodology, to a more cost-reflective basis, inevitably introduces changes in the level of income recovered from within the customer groups, whilst maintaining the same level of overall income recovery. At the highest level this represents a 2% increase in LV income recovery and a 16% reduction in HV income recovery. EHV income remains unchanged as we have not changed the methodology for these customers. The high level movement in income recovery described above has the unintended consequence of going some way to mitigating the concerns recently expressed by independent distribution network operators (IDNO's).

7.2 NEDL - illustrative charges

The illustrative NEDL charges for all LV and HV tariffs are detailed in **appendix 3** of this document. We must reiterate that these are **NOT** indicative 2007/08 prices, rather they have been calculated in a way designed to allow fair comparison of the old and new methodologies on a like-for-like basis.

The application of these charges shifts the balance of income recovery between the three main billing categories (unit, fixed and availability charges) as follows.



Overall the income recovery is unchanged. However, under the new approach we will see a 17% decrease in fixed income recovery and a 9% and 5% increase in unit and availability income respectively.

7.3 NEDL - effects on the average annual charges

Appendix 4 shows the effects of the illustrative prices on the average annual DUoS bills in the NEDL distribution services area for all customers. The table below shows a representative selection of tariffs from each customer group.

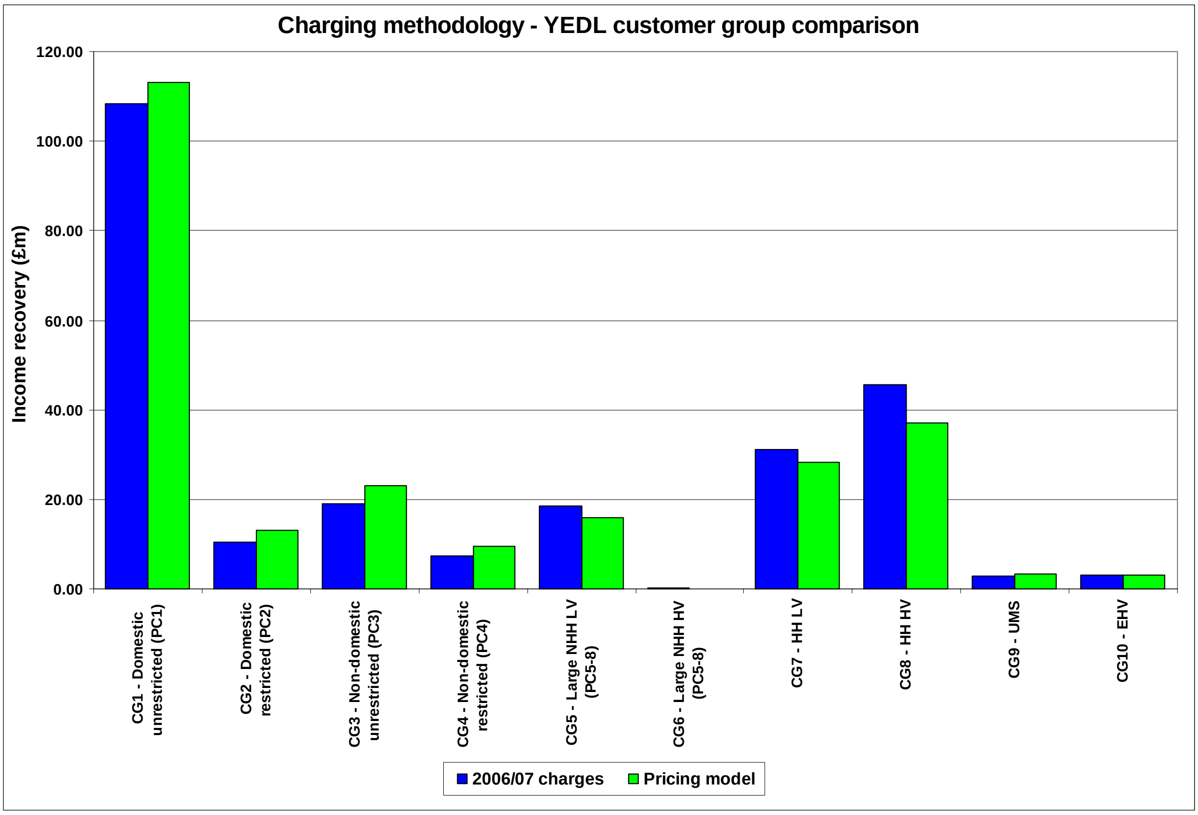
Tariff Description	LLF	Market	Customer group	Number of customers	2006/07 charges	500MW network model
Dom UR (PC1)	1	NHH	CG1	1,132,874	£64	£69
Dom Restricted (PC2)	2	NHH	CG2	95,197	£66	£72
Dom OP (PC2)	12	NHH	CG2	26,678	£9	£28
Non-Dom UR (PC3)	203	NHH	CG3	71,697	£256	£170

Tariff Description	LLF	Market	Customer group	Number of customers	2006/07 charges	500MW network model
Non-Dom Restricted (PC4)	204	NHH	CG4	13,409	£282	£192
NHH 15-50kW (PC5-8)	257	NHH	CG5	5,717	£1,024	£1,005
NHH 15-50kW SR (PC5-8)	256	NHH	CG5	9,142	£963	£785
NHH HVStd <100kW (PC5-8)	304	NHH	CG6	51	£2,076	£903
HH LV Std >100kW	251	HH	CG7	3,506	£5,571	£7,260
HH HV Std >100kW	301	HH	CG8	680	£29,771	£25,001

The table and tariffs above represent nearly 90% of the overall customer base.

7.4 YEDL - income recovery comparison

The impact on annual income recovery of implementing the new methodology, in YEDL, on the aforementioned customer groupings is shown in the chart below.



The movement in income recovery can be expressed in terms of the actual movement or the percentage movement from the currently published 2006/07 charges current. The table below displays the absolute and percentage movements, for each customer group.

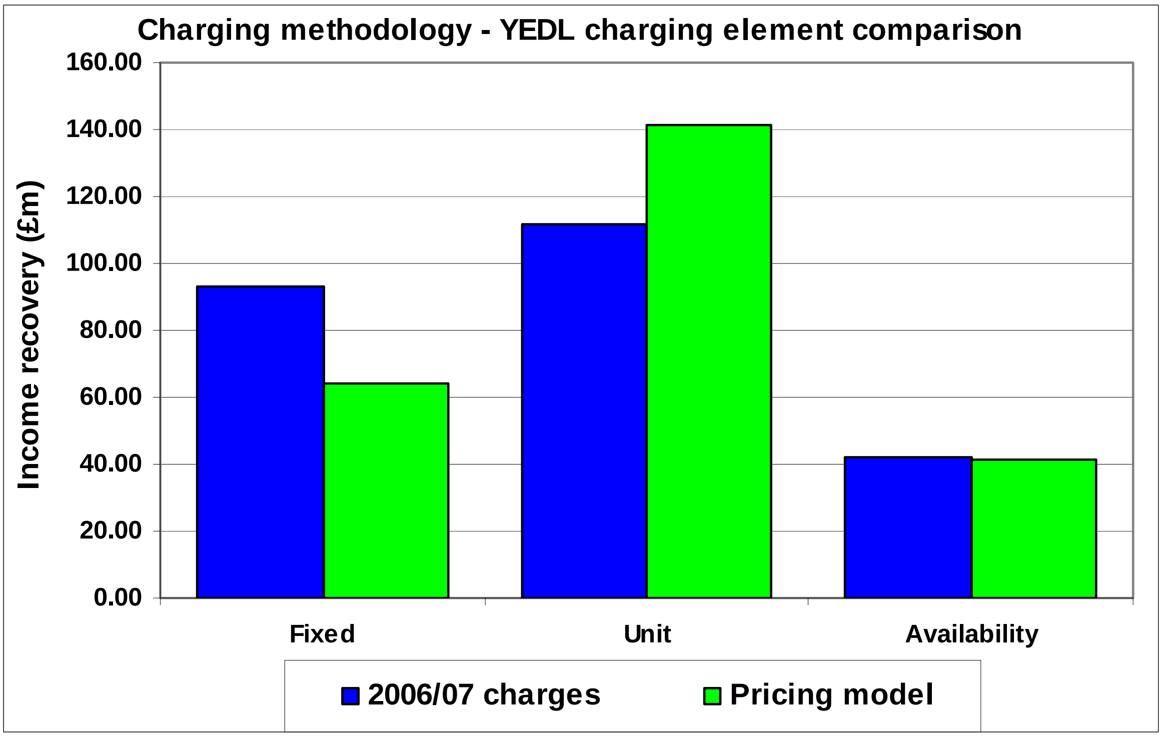
Customer group	2006/07 charges group costs (£m)	Pricing model group costs (£m)	Variance (£m)	% Variance
CG1 - Domestic unrestricted (PC1)	108.26	113.2	4.91	5%
CG2 - Domestic restricted (PC2)	10.55	13.09	2.55	24%
CG3 - Non-domestic unrestricted (PC3)	19.04	23.00	3.96	21%
CG4 - Non-domestic restricted (PC4)	7.26	9.57	2.32	32%
CG5 - Large NHH LV (PC5-8)	18.62	16.02	-2.60	-14%
CG6 - Large NHH HV (PC5-8)	0.14	0.03	-0.11	-81%
CG7 - HH LV	31.08	28.37	-2.71	-9%
CG8 - HH HV	45.65	37.01	-8.65	-19%
CG9 – UMS	2.94	3.28	0.34	12%
CG10 – EHV	3.13	3.13	0.00	0%
Total	**246.67**	**246.67**	**0.00**	**0%**

Again, as with the NEDL figures above, although there are movements in the amount of income recovered from each customer group we believe that this revised approach results in the more cost-reflective recovery of income shown in the table above. At the highest level this represents a 4% increase in LV income recovery and a 19% reduction in HV income recovery. EHV income remains unchanged as we have not changed the methodology for these customers. Again the high level movement in income recovery described above has the unintended consequence of going some way to mitigating the concerns recently expressed by independent distribution network operators (IDNO's).

7.5 YEDL - illustrative charges

The illustrative YEDL charges for all LV and HV tariffs are detailed in **appendix 5** of this document. Again, we must reiterate that these are **NOT** indicative 2007/08 prices, rather they have been calculated in a way designed to allow fair comparison of the old and new methodologies on a like-for-like basis.

The application of these charges shifts the balance of income recovery between the three main billing categories (unit, fixed and availability charges) as follows.



Overall the income recovery is unchanged. However, under the new approach we will see a 31% and 2% decrease in fixed and availability income recovery respectively and a 26% increase in unit income. These movements are larger than those seen in NEDL due to the fact that previous YEDL unit charges were much closer aligned to regulatory allowances than was the case in NEDL.

7.6 YEDL - effects on the average annual charges

Appendix 6 shows the effects of the illustrative prices on the average annual DUoS bills in the YEDL distribution services area for all customers. The table below shows a representative selection of tariffs from each customer group.

Tariff Description	LLF	Market	Customer group	Number of customers	2006/07 charges	500MW network model
Dom UR (PC1)	100	NHH	CG1	1,639,286	£58	£61
Dom Restricted (PC2)	120	NHH	CG2	144,092	£64	£78
Dom OP (PC2)	111	NHH	CG2	20,553	£6	£15
Non-Dom UR (PC3)	240	NHH	CG3	101,202	£188	£227
Non-Dom Restricted (PC4)	246	NHH	CG4	19,346	£237	£277
NHH LVStd <100kW (PC5-8)	290	NHH	CG5	8,260	£1,836	£1,614
NHH HV Std <100kW (PC5-8)	580	NHH	CG6	33	£4,257	£817
HH LV Std >100kW	281	HH	CG7	3,342	£5,604	£5,185
HH HV Std >100kW	581	HH	CG8	1,730	£23,195	£19,066

The table and tariffs above represent nearly 90% of the overall customer base.

8 Proposed wording of methodology statement

The proposed new wordings for section three of our UoS charging methodology statement - "Methodology for calculating general LV and HV demand charges" is contained in **appendix 7** to this document. The text is the same for both NEDL and YEDL and will be a straight replacement of the existing section 3. A copy of the current methodology statement can be found on our web site.

For the NEDL statement use the following link

http://www.ceelectricuk.com/lib/liDownload/158/NEDL%20Use%20of%20system%20charging%20methodology%20v1_5.pdf

For the YEDL statement use the following link

http://www.ceelectricuk.com/lib/liDownload/161/YEDL%20Use%20of%20system%20charging%20methodology%20v1_5.pdf

9 Conclusions

The new CE pricing model for low voltage (LV) and high voltage (HV) connected customers is based on the long-run marginal costs of the network and the operating costs identified from our regulatory reporting packs (RRP). The model is a customised version of the EA Technology cost allocation spreadsheet developed in the late 1990s and adopts the same principles as those used in the original Electricity Council distribution reinforcement model (DRM) developed in the 1980s. The methodology produces average charges for the mass market LV and HV customers and maintains site-specific charges at EHV.

The Authority's conditional approval requires that CE should progress with urgency the development of a revised charging model based around the comments and views provided in the Authority's letter to ensure that any revised model achieves the relevant objectives to develop and implement a new charging model by 1 April 2007.

Our proposals address these concerns by replacing the current approach, which starts from the assumption that existing charges are cost-reflective (without actually providing evidence of this), with a methodology based on long-run marginal costs founded on a 500MW network that reflects the manner in which the NEDL and YEDL networks are to be developed, ensuring that the tariffs are based on our underlying costs. It is intended that this new approach will be implemented (if approved) by 1 November 2006.

We believe that our new methodology better meets the licence conditions in the following areas:

- It is based on forward-looking costs and, as such, ensures that costs are reflected back to customer groups based on the cost they generate;
- It represents an equitable and cost-reflective mechanism for allocating costs in order to set tariffs;
- It is relatively simple and transparent and should be easily understood by our customers as it is founded on the same principles as methodologies already approved by the Authority for a number of other DNOs.
- It uses asset-based yardsticks (based on MEA prices and technologies) as its prime cost driver, which is regarded as the most representative means of allocating future network cost to different customer groups;
- It uses opex costs that are based on audited regulatory reporting pack data and allocates these on both an asset and customer basis, dependent on the nature of the cost;

- As this is a long-run cost model the approach has the potential to be part of the enduring solution, particularly for customers connected at lower voltages; and
- In addition to addressing Ofgem's concerns, we believe the changes also better meet other relevant licence objectives, principally by increasing cost-reflectivity and facilitating competition due to the greater transparency and understanding of the proposed approach.

Hence, we believe that this proposal better meets our licence obligations and the evidence in this report provides a firm basis for the removal of the conditions on our methodology.

10 Next steps

Assuming we gain approval of this revised methodology the following key activities will be mobilised:

- We will use the proposed methodology to set the indicative charges for 2007/08, which will be announced in late December 2006: and
- We intend to hold a seminar/workshop for suppliers and large end users within our area to explain the methodology (post-approval – 2 November) - Current thoughts are that this should become an annual seminar to provide an early indication of potential changes, prior to indicative charges.

In respect of longer-term arrangements;

- We shall continue to collaborate with other industry players and Ofgem in moving towards an enduring solution; and
- We shall actively participate in the collaborative working with other DNOs through the Energy Networks Association (ENA).

Appendix 1 – Final report from DLT Consulting (David Tolley)

CE-ELECTRIC PROPOSAL FOR A DISTRIBUTION REINFORCEMENT MODEL

A report by DLT Consulting following a review on 21st/22nd June 2006

EXECUTIVE SUMMARY

This report provides a commentary on CE-Electric's progress in developing a DRM on which to base DUoS charges in the immediate future. It takes a snapshot of the position on 21st and 22nd June 2006. It notes CE's research into the origins of the DRM and offers some rationalisations of specific features found in the original DRM introduced by the Electricity Council (1984) and subsequently updated by Electricity Association Technology (1998). Changes introduced by EAT were intended to reflect changes in market conditions but further market developments make continuous evolution of the DRM necessary.

An overview of the CE-Electric DRM as it is currently construed focuses on the creation of a 500 MW asset model that reflects the manner in which the NEDL and YEDL networks are expected to develop in the future. The assumptions in the model have been reviewed for their appropriateness in the current market conditions, and for their internal consistency. Specific attention has been paid to the manner in which the capital charges in the model are expressed as annual costs, and how operations and maintenance costs are allocated back to particular parts of the network. The derivation of the availability charge has been contemplated and the importance of its interaction with connection charging policy considered.

The concluding section of the report makes 9 recommendations concerning the treatment of costs in the model and the internal consistency of the data and assumptions. It is understood that some of these suggestions have already been incorporated in the model and the others will be reviewed in due course for their applicability.

.

INTRODUCTION

1. In its letters of 20th December 2005[6] Ofgem requested that CE Electric, acting on behalf of Northern Electricity Distribution Ltd (NEDL) and Yorkshire Electricity Distribution Ltd (YEDL), devise a new distribution use of system model to be approved and put in place by 1 April 2007. DLT Consulting has been retained by CE Electric to comment on their proposals for such a model as they stood on 20th and 21st June 2006. Without prejudice to its development of an enduring arrangement for use of system charges, CE Electric has chosen to devise a charging model for application from 1 April 2007 based on the Distribution Reinforcement Model (DRM) principles that are generally in use by most distribution businesses.

Evolution of the DRM

2. The DRM is not a formulaic model but a prescribed approach that enables the costs of a distribution network to be allocated to specific classes of customer. In the context of the price control it has been used as a basis for allocating the revenue a distribution business is permitted to raise to the users of its network.

3. In order to develop its proposals for a DRM CE Electric has comprehensively researched the history of the DRM. Its origins are to be found in the approach to the derivation of electricity tariffs proposed by Boley and Fowler in 1977[7], and subsequently developed in the Electricity Council Tariff Formulation Manual[8]. The exposition of the DRM in this context was against the legislative framework of a nationalised industry where the tariff formulation needed to take account of statutory obligations and Government policies concerning:

   - The recovery of costs (s.13 Electricity Act 1957)
   - Basing charges on Long Run Marginal Costs (LRMC) (1967 White Paper on Nationalised Industries economic and financial objectives Cmnd 3437)
   - Not showing any discrimination or preference to customers or classes of customer (s.37 Electricity Act 1947)
   - Earning a 5% return on capital employed (1978 White Paper on Nationalised Industries Cmnd 7131)
   - Statutory rights of connection (s.27 Electric Lighting Clauses Act 1899)

[6] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/13349_CE_NEDL_201205_charging_model_decision_letter.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/distributioncharges/edc2
http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/13348_CE_YEDL_201205_charging_model_decision_letter.pdf?wtfrom=/ofgem/work/index.jsp&section=/areasofwork/distributioncharges/edc2

[7] Boley, TA and Fowler GJ (1977). The basis for cost reflective tariffs in England & Wales. IEE Third International Conference on Metering Apparatus and Tariffs for Electricity Supply pp. 30-36

- Removal of the monopoly of generation for public supply from state owned monopolies and the introduction of "availability charges" (Energy Act 1983)

4. Since its original inception the DRM has had to cope with a number of fundamental changes in the structure of the industry and its regulatory backcloth. Most obviously the privatisation of the electricity industry in 1990 replaced the regulatory framework of cost recovery and a target rate of return coupled to external funding limits and overt approval of investment programmes with a price control revenue target and associated RPI-X incentive for cost efficiency. The Electricity Act 1989 repealed the Acts of 1947 and 1957 and through them the provisions of the Electricity Lighting Clauses Act of 1899, whilst the Utilities Act 2000 further amended the regulation of the industry.

5. The progressive removal of the supply franchise from the Regional Electricity Companies meant that the DRM needed to focus solely on those costs concerned with the use of the network to the exclusion of costs associated with the supply of electricity. Most recently the introduction of competition in metering has made it appropriate for metering costs also to be excluded from the DRM.

6. Despite the substantial revision in the regulatory and statutory backcloth the application of the DRM in many distribution businesses appears to have been relatively stable. An EA Technology study9 for 7 distributors conducted in 1997 and 1998 reviewed the development of the DRM and considered concerns raised by the participating companies in its application. The various features of the model were reviewed and discussed. Some of the issues raised are re-visited in the discussion below.

7. The EA Technology project proposed a uniform framework for the cost allocation model as a generic spreadsheet known as "eaCASS", although this was closely followed the spreadsheets derived from the original Electricity Council model. It was intended that the model would be populated with an individual distributor's cost data, and modified if appropriate to cater for local circumstances. The DRM proposed by CE Electric uses a spreadsheet that has been developed from the format of "eaCASS" but has re-examined the appropriateness of some of the allocation principles and algorithms in the light of the current market structure. Separate versions of the spreadsheet reflect local data for NEDL and YEDL. The contents of the model are summarised below.

---

[8] Tariff Formulation Manual, Second edition. The Electricity Council Commercial Department June 1984
[9] Cost allocation in distribution monopolies – turning theory into practice EA Technology report N^{o} 90607 November 1998

CE ELECTRIC DRM

Overview

8. CE Electric's DRM is contained in an 11 page spreadsheet whose pages deal with the aspects listed below. In accordance with the general framework of the DRM it sets out to identify the costs of the distribution network at each of 7 levels comprising:

   - 132 kV circuits and their terminating switchgear
   - 132/33 kV transformations
   - 33 kV circuits
   - 33/11 kV transformations
   - 11 kV circuits
   - 11kV/LV transformations
   - LV circuits

9. **Page 1** - The initial page of the spreadsheet contains the asset register that forms the 500 MW model together with the assumed diversity factors at each voltage level. Each asset is costed at its modern equivalent asset (MEA) value and then converted to an annualised charge per kW of demand using an appropriate annuity factor. Costs are increased by the aggregate electrical losses at each voltage level

10. **Page 2** - This page identifies 10 tariff classes ranging from unrestricted domestic customers through to EHV customers. Forecasts of numbers of customers and their annual consumption are specified. A customer weighting factor (see below) together with the class load factor (in hours per annum) power factor, coincidence factor and class loss factor are all identified. In the case of the three half hourly customer classes applicable to customers connected to the LV, HV and EHV networks the agreed service capacities are also noted here.

11. **Page 3** - This page converts the network costs given in page 1 into a pence per kWh costs at each network level using the customer class parameters from page 2. The page also includes an LV factor for LV connected customer classes that can take a value of either 0.5 or 1.0.

12. **Page 4** - Network operating costs are detailed on this page. These costs are those approved as part of the regulatory price control. The model has the capability to allocate these costs to the 10 customer classes on the basis of a number of parameters already identified within the model, such as numbers of customers, system maximum demand (SMD), asset values, etc.

13. **Page 5** - The forecast revenue anticipated from the customer groups in respect of network capital charges is calculated on this page. This calculation includes an allocation of grid exit charges which reflect the costs of connection to the transmission network. The result is expressed as both pence/kWh and total revenue recovered for each customer class.

14. **Page 6** - This page makes a similar calculation for the operating costs from page 4. However, in the example considered here these are allocated to customer classes on the basis of customer numbers weighted by the customer factors noted on page 2. The total allocation of operating cost to each class is expressed in £million.

15. **Page 7** - An accumulation of the network costs and operating costs by customer class is shown on this page.

16. **Page 8** - The proportion of the overall cost that will be recovered by way of an availability charge is calculated here. The input to the table includes the proportions of the yardstick costs that are to be recovered against the agreed service capacity at the voltage of connection, the transformation immediately above it, and circuits at the next higher voltage.

17. **Page 9** - This page summarises the outputs of the model for each customer class. The table indicates the nature of the charge in terms of a p/kWh charge, a £/kVA charge, and a fixed charge per customer. The overall forecast revenue that will be recovered and the average charge per customer per annum are the final columns of this table.

18. **Pages 10 & 11** - The assumptions made in deriving the model inputs are noted here.

MODEL ATTRIBUTES

The Asset register

19. The heart of the DRM is the asset model. This is a model of the physical network it is expected will be needed to meet an increment of 500 MW at each voltage level. Roughly speaking the assumed network would be equivalent to a new grid supply point (GSP). This reference network does not seek to describe the existing asset structure but instead endeavours to represent the mix and nature of assets it is anticipated will be needed in the future. The network is thus a hypothetical construct and inevitably embodies considerable engineering judgement.

20. However, in doing this it can reflect the inherent features that are expected for the network's development. It can also reflect topographical features such as the long "stringy" sections of network that include 66kV as well as 33 kV assets that characterise development in the NEDL area, and the highly meshed 33 kV network that is a feature of

the YEDL distribution network. It is understood that the network model proposed incorporates the additional network capacity that is needed to meet the planning standard requirements of Engineering Recommendation P2/6.

21. Although CE Electric has devised a single DRM, separate versions of model have been populated with different assets and customer data that reflect the forecast characteristics of the development of the NEDL and YEDL networks. For comparative purposes CE have also created a model of the totality of the NEDL and YEDL networks that incorporate all existing assets as detailed in the asset register that is declared to Ofgem in table 3.2 of the Regulatory Reporting Pack. Assets in both models have been valued at their current prices, or where the specification is no longer available at the current cost of the most equivalent asset. When scaled from 500 MW to the system maximum demand the DRM asset values show a considerable disparity with a model based on the asset register.

	DRM Asset value 500 MW	System Maximum Demand	DRM asset value scaled to SMD	Full network asset value
NEDL	£216 M	5,589 MW	£2,414 M	£7,412 M
YEDL	£296 M	8,766 MW	£5,168 M	£11,000 M

22. The disparity between the valuation of the DRM and the assets that comprise the existing network illustrates the incremental nature of the investment contemplated in the 500 MW model. It is unsurprising that the incremental or marginal cost of the system will be significantly lower than the replacement cost of the extant network. The longevity of the network assets, the provision of much of the network to service previous economic activity and meet wider public policy objectives, and the significant technological improvement that has occurred in the design of network assets all tend to mean that incremental demand can be serviced at a lower cost than the cost of the present network. Basing charges on the incremental investment anticipated should provide the correct economic signal of cost for users.

Diversity Allowance

23. The DRM anticipates that there will be a natural diversity between the demands of individual customers connected at each voltage level and the maximum demand that must be met by the network at that voltage. This enables a network with a 500 MW capacity at each voltage level to service a higher aggregate of customer demands

connected at that voltage. The original Electricity Council DRM[10] included the allowances for diversity shown below. These show the maximum demand of the customers that could be accommodated at each voltage level in relation to the simultaneous demand on the network.

Network Level	Network SMD	Diversity Allowance	Aggregate customer MD
132/33 kV	500 MW	6%	530 MW
33/11 kV	500 MW	12%	560 MW
11 kV/LV	500 MW	34%	670 MW

24. These allowances have been read through into the proposed CE model. It might be appropriate to sample a number of parts of the network to demonstrate that they can be viewed as representative of the NEDL and YEDL networks since their derivation was over 20 years ago when the mix of load was somewhat different to that found today. Furthermore they were ever generic national averages when originally divined.

Annualising capital charges

25. The assets in the 500 MW model are valued at their MEA value and then converted to an annual per kW amount by applying an annuity based on the cost of capital. The CE model adopts the regulatory cost of capital of 6.9% assumed for the price control period. This also appears to be the practice of other DNOs.

26. In the EC model the cost of capital was expressed as an annuity factor on the basis of a 40 year asset life. The annuity factor was then was then increased by an allowance of 2% (in some references this is 1%) to account for what at the time was referred to as a "tilt" in the annuity factor[11]. It was noted that the "tilt" was designed "to reflect increases in repair and maintenance costs, the effect of improvements in technology, and the obsolescence produced by shifting load patterns after the first year".

27. The EA Technology report struggles with the concept of the "tilt". It observes that since capital costs are recalculated annually for the network assets any technological change that occurred would automatically be incorporated in the model. Furthermore since the DRM is an "abstraction of reality" it is inappropriate to imagine that assets can become "stranded" before the end of their useful life. The recommendation from the EA

[10] Table C1 page 54 Electricity Council Tariff Formulation Manual
[11] Electricity Council Tariff Manual 1984, Appendix D, page 58

Technology project was that the “tilt” factor should be discarded and the capital charges assessed purely from the cost of the capital, which is the approach adopted in the “eaCASS” spreadsheet. This would appear to have been something of a retrograde step.

28. The body of the EC Tariff Manual has a much simpler exposition of the need for a “tilt” in the annuity. It notes simply that it is necessary to increase the annuity factor that is derived from a 40 year asset life to account for a more rapid decline in the earning power of the assets than is implicit in the depreciation allowance embedded in the annuity. This would seem a much more compelling rationale.

29. Unless the annuity is adjusted in some manner the DRM will intrinsically assume that the income stream obtained from the incremental investment will persist over the 40 year accounting life ascribed to the asset, which must be an optimistic if not courageous assumption. The substantial difference between the DRM asset valuation and that of the extant network (see paragraph 21 above) illustrates how the economic value of the network assets decline much more rapidly than their physical life.

30. It is understood that a 20 year depreciation period is assumed in the price control calculation. If this were used to reflect the decline in the earning power of the DRM 500 MW assets then the annuity factor would become 9.37% in place of 7.41% for a 40 year asset life: a “tilt” in the annuity of just under 2%!! It is suggested that it would be appropriate for the 9.37% factor to be used when calculating the annualised cost of the DRM assets.

31. In fact much of this discussion may prove academic. If there is a shortfall in the revenue recovery as the result of using a lower annuity factor and this were recovered as a £/kW uplift to charges then it would have the same impact as using a higher annuity factor in the first place.

O&M Costs

32. The original EC DRM incorporated network operations and maintenance costs of the network as a percentage of the MEA value of the assets. A supplement of 2.25% was added to the annuity factor which effectively allocated the O&M costs in proportion to the asset values. The EA Technology development of the model supplants the flat percentage assumption with the actual O&M costs approved as part of the price control. CE has adopted the EA Technology approach in the construction of its model. The approved operating costs are brought out as a separate page (4) in the spreadsheet and there is discretion as to how to allocate these in accordance with various parameters.

33. CE report operating costs in four categories; viz. direct activities, indirect activities, non-activity related and statutory depreciation. 80% of the operating costs are attributable to the direct activities of faults, inspection and maintenance, network rates and statutory depreciation provisions. The repairs of faults and network maintenance are directly related to the extant assets, as presumably are the statutory depreciation provisions.

34. It is understood that the Rateable Value of the network, and thus the eventual determination of the rates that will be incurred, is driven by the earning capability of the network. This in turn derives from the asset values in the DRM. It would thus seem to follow that the cost of Rates should be allocated back to the asset values and thence to the customers who use them.

35. The general conclusion that is reached is that an allocation of operating costs on the basis of asset values, which was the effect adjustment to the annuity factor in the original Electricity Council model, remains the most appropriate approach, unless significant variation in these costs at different voltage can be demonstrated. However, a distinction might be drawn between Rates that should be allocated on the basis of DRM assets, and other operating costs which might be allocated according to the distribution of the full network assets. Once the allocation has been arrived at from the extant network the relevant cost proportions could be inserted at the appropriate level in the DRM. An exception to these general rules could be the Finance and Regulation costs and legal and company secretariat costs.

Customer Class Parameters

36. The customer numbers, class load factors (hours per annum), and forecast consumptions in the CE DRMs have all been derived from NEDL and YEDL billing data and thus reflect the actual features of the customer population. Loss factors for each of the voltage levels that are used to inflate the network capacity required to service the 500 MW of simultaneous maximum demand are also consistent with the line loss factors attached to each customer class.

37. Yardstick coincidence factors in the model, that show the relationship between customer demand and the SMD at a higher voltage, are used to determine the proportion of the network at higher voltage levels that is attributable to each customer class. These have also been derived separately from billing date for NEDL and YEDL customers. However, the coincidence factors in the calculation of the availability charge have a different origin as noted below.

38. The CE models use an assumed power factor of 0.95 for all loads thus increasing the required network capacity to service a kW of demand by 5%. The assumption is widely

used throughout the industry as has always been the case, but probably has little substance in its foundation. The reality is that the DRM is incapable of either identifying or appropriately allocating the costs of reactive power. These can only be determined by reference to an AC load flow model and would need to take account of the possibility of installing local compensation to accommodate reactive flows rather than simply assuming that the network should be expanded, which is the approach implicit in the DRM.

Grid Exit Charges

39. Grid exit charges relate to transmission assets that connect the 132 kV circuits to the transmission system. Under the current shallow connection charging policy they relate to little more than the switchgear and some associated equipment in the 400/132 kV or 275/132 kV NGC sub-station. The approach taken in the CE DRM is to allocate these annual costs to customer classes on the basis of the contribution class demand makes to SMD. This is also the practice adopted in the calculation of site specific distribution charges for EHV connected customers.

40. Physically the grid connection assets represent an extension of the 132 kV network. In the context of the DRM they could therefore have been incorporated in the model of the 132 kV network by expressing them as additional assets whose value was such that the lifetime DRM charges equated with the lifetime connection charges levied by National Grid. Although such an approach would seem rationale it would produce a different result to the approach that CE has taken. The reason for this is that National Grid connection charges are derived from the historic cost of the assets depreciated over a 40-year life with an associated rate of return earned on the net asset value. Grid exit charges will therefore display a saw tooth profile over time with charges gradually declining but then increasing sharply when grid sub-stations are re-planted.

41. This is not a matter for discussion here, but if the DRM were to become an enduring methodology at higher distribution voltages then thought might be given as to whether charging for assets that join a distribution network to the transmission system as connection assets is the most appropriate approach. An alternative approach might be to treat them in the same manner as any other 132 kV asset in the DRM.

Customer Weighting Factor

42. The CE DRM includes the same customer weighting factors that are found in the eaCASS spreadsheets. These factors range from unity for profile class 1 customers, through 1.1 for profile class 2 customers to 16 for half hourly customers connected at HV. The purpose of the weighting factor is to adjust the number of customers in each

class before the allocation of “non-operational” costs. These factors also have their origins in the Electricity Council Tariff Manual. In the EC methodology they related predominantly to metering and billing costs in an era when the yardstick cost calculation applied to both supply and distribution costs.

43. The relativities of the factors between customer class appear to have more to do with the complexity of metering than any other non-operational cost. Since metering costs now reside outside the regulatory price control it may no longer be appropriate to incorporate these factors within the model, or rather to do so would serve no purpose. The costs of billing suppliers should be capable of being discerned from the central systems and could be allocated directly to the relative customer classes on the basis of the MPAN count.

Availability Charges

44. Page 8 of the CE DRM incorporates the same routine found in the EA Technology version of the DRM to calculate an “availability charge”. This is assessed by separating out the bulk of the network costs at the voltage of connection and 20% of the costs of the circuits at the next voltage level.

45. The origins of the availability charge are to be found in the Energy Act 1983 which required Area Boards to offer terms for providing a supply to distributed generators in the event that the private generation was out of service. The usual charge out arrangement for non-residential customers was for the availability charge to be applied to an agreed service capacity rather than any metered quantity. The availability charge thus recovered the costs of the system immediately adjacent to the user. The costs of the system at higher voltages were recovered through a p/kWh charge and thus only applied when the site load, which was normally supplied by the private generator, was drawing power from the distributor’s network.

46. The boundary between charging for use of the network against an agreed service capacity and as a per kWh amount is somewhat arbitrary. The rationale for the original distinction is probably still appropriate but the point in the network at which the assets are deemed for the general use of customers as opposed to the predominant use of a specific customer remains open to interpretation. There is also an interaction between the availability charge and the connection charging policy that is adopted.

47. At present the proposed CE DRM continues to employ the coincidence factors drawn from the EA Technology version of the model, which in turn draws on those found in the Electricity Council Tariff Manual. Since CE has calculated coincidence factors

separately for its own network it would seem appropriate that these should also be used in the derivation of the availability charge, if they are still seen as appropriate.

Connection Charges

48. The Electricity Council Tariff Manual articulates the connection charging policy that existed at the time the availability charge was introduced. Broadly speaking the approach was to divide the costs of making a connection between the new load and reinforcement on the basis of the kVA capacity that was provided for both. This is in line with the principle adopted from 1 April 2005 for present DNO connection charges. The cost of effecting the new connection was then reduced by the support provided by the tariff. Although the calculation would depend upon the extent of the capital scheme and the characteristics of the new load, the support provided by the tariff might in most circumstances be expected to be close to the availability charge.

49. The present method for calculating connection charges does not make reference to the tariff support provided by the availability charge. This may give rise to concerns over prospective double counting of costs. Since connection charge revenues are separately regulated from the revenue target a clear rationalisation is needed as to how connection charges interact with DUoS charges. This is not to suggest that the DRM should be modified to accommodate the connection charging policy, but rather that the derivation of connection charges should take account of the principles within the DRM.

Residential service cables

50. The EC Tariff Manual describes the identification of a “Minimum Supply Cost” for providing supplies to residential households. The MSC was in turn recovered through a combination of a Standard Connection Charge and the fixed quarterly standing charge in the supply tariff. In order to reflect this in the DRM the EC model introduced an “LV factor” that reduced the costs of the LV distribution network that would be recovered through the use of system charge in the supply tariff. The LV factor took the value of 0.5 for quarterly billed customers and 1.0 for monthly billed customers.

51. The initial version of the EA Technology DRM excluded the costs of the services to residential households. With the ending of the REC franchise for supplying residential customers, thus requiring all costs to be recovered through a separate distribution use of system tariff. it was seen as appropriate that the cost of the services should be incorporated in the DRM. This had the effect of significantly increasing the £/kW cost of the LV part of the model.

52. It is understood that CE are considering excluding the residential service cable costs from the DRM on the grounds that it would be anticipated that these would usually be

recovered as part of the capital contribution paid by developers. As in the case of non-domestic premises a clear rationalisation needs to be given as to which costs are being recovered through the DRM charges, and those recovered as part of the connection charging policy.

Working capital

53. At present the DRM has no explicit recognition of the working capital costs of the distribution businesses. The annuity used to derive the annual capital charges is calculated on the basis that the income stream lags one year behind the investment. This may be a reasonable assumption if the MEA values include interest during construction (IDC). However, it may be appropriate to calculate the working capital costs incurred for each class of customer as a result of the lag between the incidence of operating costs and their recovery from suppliers through DUoS charges and show this explicitly in the tariff yardstick calculation.

CONCLUSIONS & RECOMMENDATIONS

54. The tariff model currently in use by CE-Electric adjusts the previous year's tariff for volume changes in the customer base, and then for changes in the permitted revenue recovery under the price control. Tariffs for individual customer classes are scaled uniformly to reconcile the revenue with the target. An obvious weakness with this approach it that it implicitly assumes that the tariff for the previous year, which becomes the basis for charges in the subsequent year, is reflective of the underlying costs.

55. In moving to a DRM founded on a reference 500 MW network that reflects the manner in which the NEDL and YEDL systems are likely to develop CE is looking to ensure that the tariff is based on its view of future costs. CE Electric has carefully researched the basis of the DRM as originally proposed by the Electricity Council and subsequently developed by EA Technology. In doing so they have revealed that some of the practices in the DRM were founded on policy objectives or market arrangements that may no longer be wholly appropriate. CE's development of a DRM to apply in the NEDL and YEDL areas provides an opportunity to bring the DRM into line with current market practices.

56. CE's model was still under development when this review was undertaken. Consequently any proposals made at this stage should be seen as being part of the overall development of an appropriate model. The following suggested amendments to the structure in being when this study was conducted have been noted in this report:

    i. Assess whether the Diversity Allowances in the original EC model are appropriate for the NEDL and YEDL networks

ii. Consider using an annuity factor of 9.37% instead of 7.41% to calculate the annualised costs of the 500 MW network model

iii. Identify those operational costs that relate to assets and allocate them on the basis of asset costs derived from the full network model rather than the DRM

iv. Allocate rates in accordance with the assets incorporated in the 500 MW DRM

v. Discard the customer weighting factors from the model since these relate mainly to metering costs, and consider replacing them with an algorithm that better reflects the billing costs of central systems

vi. Consider whether it is appropriate to continue to use coincidence factors in the calculation of the availability charge, and if so whether they should reflect the characteristics of the present day NEDL and YEDL customer demands

vii. Rationalise the relationship between the calculation of the availability charge and the determination of connection charges

viii. Exclude LV service cable costs from the DRM asset base to the extent that they are recovered by connection charges, but again rationalise how these costs mesh with the connection charge policy

ix. Include, at least in principle, a working capital component in the yardstick calculation, always assuming that there is an associated cost

Appendix 2 – Consultation letter

Your Ref

Our Ref

98 Aketon Road
Castleford
WF10 5DS
Tel: (01977) 605932

e-mail: andy.jenkins@ce-electricuk.com

XXXX
XXXX
XXXX
XXXX
XXXX
XXXX
XXXX
XXXX

26th May 2006

Dear XXXX

Development of CE Electric UK charging methodologies

CE Electric UK Funding Company (CE) is the UK parent company of Northern Electric Distribution Ltd (NEDL) and Yorkshire Electricity Distribution plc (YEDL).

We are writing to inform you of our plans to change the way we calculate the use of system (UoS) charges that relate to the distribution of electricity to your customers premises and to seek your comments on these changes.

Background

On the 16th February 2006 we wrote to Ofgem and suppliers informing them of our UoS charges for 2006/07. These were based on our existing charging methodology which was subject to certain conditions imposed by Ofgem. These conditions need to be addressed by April 2007, namely:

- Charges applicable from 1 April 2006[12] should be set using the current model rather than the revised approach;
- CE should progress with urgency the development of a revised charging model based around the comments and views provided by Ofgem to ensure that any revised model achieves the relevant objectives set out in our licence;
- Due to the extension of timescales for completion of this condition CE should also consider other developments in the industry, such as the studies into electricity distribution charging models during the course of this year, when considering a revised model; and

[12] This condition excludes EHV customers whose charges have been determined and the approach approved by the Authority – decision letters of 7 December 2005.

- CE should develop a revised UoS charging model to be approved by Ofgem and in place by 1 April 2007.

Having reviewed our current methodology we recognise that there are some improvements that can be made to enable our charges to better meet the relevant objectives that are imposed upon us by our regulatory regime. In particular, a revised charging structure would better enable us to meet the requirements that we avoid discrimination by ensuring that we allocate costs more appropriately to the different customer groups; and the requirement that we achieve improved cost reflectivity in our charges.

The purpose of this letter is to inform you of our plans to develop a new charging approach to facilitate the satisfaction of the above conditions and to provide you with the opportunity to comment.

New Proposals

It is our intention to develop a new pricing model, which should have the benefit of improving the standardisation and alignment of our published tariffs. Our initial thoughts on the key elements of our proposed approach are as follows:

- For LV and HV demand customers we intend to re-instate a distribution reinforcement type model (DRM) based on forward looking costs. The model will utilise network asset information and business costs in conjunction with settlements and system utilisation data to derive yardstick prices which will then be scaled to meet allowed the revenues allowed under our price controls;
- Site-specific EHV charges will be calculated based on the outputs of our existing locational EHV yardstick model. We believe that this is a cost reflective approach which includes an appropriate allocation of costs for the provision, operation and maintenance of identified assets required in order to provide a supply of electricity for the customer, and charges that vary from location to location dependent on the individual connection. In order to improve cost reflectivity, and in discussion with Ofgem, we propose to remove the existing transitional relief arrangements; and
- We also intend to undertake a review of the level of the different charging elements of each tariff to establish any opportunities to facilitate more cost reflective charging signals, particularly for larger customers in the half-hourly market where the functionality of existing billing system will allow it.

Our aim is to complete the development of this refined approach, undertake detailed impact and sensitivity analysis and submit our proposal to Ofgem by the end of August 2006. It is expected that this new methodology will then form the basis of our charges until the implementation of the enduring long-term framework, which is due to be in place prior to April 2010.

This is a separate piece of work to the development of the enduring solution, although we fully intend to continue to work collaboratively with key industry stakeholders in order to support the development of the long-term charging arrangements. The proposals we have outlined above are specifically concerned with an interim solution to secure the satisfaction of the conditions attached to our current charging statement.

It should be noted that this letter does not constitute a formal notice of changes to the methodology or charges. Any proposal to change the methodology will require approval by Ofgem, followed by the normal three months indicative charges notice to suppliers. Given, the timeline we are working to we do not envisage any changes to our charges before April 2007, though we reserve the right to do this at any time with the appropriate period of notice.

Whilst we remain disappointed about the conditions imposed on our charging statement we are committed to finding an efficient and effective solution that meets the requirements laid out by Ofgem. This will then allow us to concentrate our efforts on the development of the enduring solution.

Specific EHV issues

Historically EHV charges were calculated differently for both NEDL and YEDL. In order to align and standardise processes and enable a sound basis for understanding how EHV income should be calculated a new set of consistent locational EHV charging models were implemented across CE Electric UK on 1 April 2005.

Inevitably the standardisation of processes, particularly those that impact the charges faced by some of the largest customers, is a sensitive subject. Hence, in recent years in agreement with Ofgem we have utilised a migration strategy that gave some transitional relief to those customers most adversely affected. This migration strategy, as it has applied until now, is detailed below:-

From April 2005

- The charge levied on all new EHV sites matched the target charge generated from the locational EHV yardstick model;
- Sites connected prior to 1 April 2005 were put on a bespoke migration strategy towards the new target charge such that, where possible, we provided price predictability and stability: -

- Those sites for which the legacy charges, calculated using previous methodologies, were above the current target EHV charge were moved to this lower level immediately;
- Those sites for which the legacy charges, calculated using previous methodologies, were below the current target EHV charges had their increase capped at 15% for the 2005/6 charging year. However, should the assets utilised in their connection have changed, then the target charge would have been applied.

This was in line with Ofgem's decision in February 2005, to consultation 284/04 – Transition of Electricity Distribution EHV demand use of system charges.

From April 2006

- The charge levied on all new EHV sites matched the target charge generated from the locational EHV yardstick model; and
- Sites connected prior to 1 April 2005 whose legacy charges were calculated using previous methodologies, and were still below the current locational EHV yardstick charge had their increase capped at RPI for the 2006/7 charging year. However, should the assets utilised in their connection be changed, the target charge will be applied.

Maintaining the transitional relief, enjoyed in recent years by some EHV customers, may be said to maintain an element of cross subsidy between customer groups in our income recovery and causes us issues with regard to the cost reflectivity of the charges faced by such customers.

Given the above, appendix 1 to this letter gives you an early indication of the likely cost reflective EHV charges, where applicable, that you could face in future years based on our yardstick models once transitional relief is ended. I must stress that these charges are only illustrative in nature and include assumptions on national grid exit charges and rates. They are also based on your site's existing agreed capacity and current network configuration, and as such do not include costs for any work that may be carried out in future years.

We hope that this letter provides a helpful insight into the work that we are currently undertaking and we will continue to keep you informed of progress. If you would like to make any comments on our proposed interim solution and likely path of EHV charges then it would be helpful to receive these by 9 June 2006. We are also happy to discuss the above with you on a one-to-one basis if you feel that would be beneficial. Please do not hesitate to contact me if you would like to do this.

If you are not the most appropriate person within your organisation to receive this notification I would appreciate it if you could forward it to the relevant person.

Yours sincerely

Andy Jenkins
Network Sales

C.C. EHV customers

Appendix 3 – NEDL - illustrative charges

				2006/07 charges				Pricing model			
Tariff Description	LLF	Market	Customer group	Fixed charge (p/cust/day)	Unit charge 1 (p/kWh)	Unit charge 2 (p/kWh)	Availability charge (p/kVA/day)	Fixed charge (p/cust/day)	Unit charge 1 (p/kWh)	Unit charge 2 (p/kWh)	Availability charge (p/kVA/day)
Dom UR (PC1)	1	NHH	CG1	7.23	0.95			5.20	1.26		
Dom UR PP (PC1)	5	NHH	CG1	7.23	0.95			5.20	1.26		
Dom UR (PC1) WO	21	NHH	CG1	7.23	0.95			5.20	1.26		
Dom UR PP (PC1) WO	25	NHH	CG1	7.23	0.95			5.20	1.26		
Dom Restricted (PC2)	2	NHH	CG2	7.27	0.99	0.12		5.44	1.30	0.19	
Dom Restricted PP (PC2)	6	NHH	CG2	7.27	0.99	0.12		5.44	1.30	0.19	
Dom Restricted (PC2) WO	22	NHH	CG2	7.27	0.99	0.12		5.44	1.30	0.19	
Dom Restricted PP (PC2) WO	26	NHH	CG2	7.27	0.99	0.12		5.44	1.30	0.19	
Dom Restr OP Hrs (PC2&4)	8	NHH	CG2	5.81	0.12			2.80	0.25		
Dom OP (PC2)	12	NHH	CG2		0.12			2.80	0.25		
Dom Restr OP Hrs (PC2&4) WO	28	NHH	CG2	5.81	0.12			2.80	0.25		
Dom OP (PC2) WO	32	NHH	CG2		0.12			2.80	0.25		
Non-Dom UR (PC3)	203	NHH	CG3	21.66	1.41			11.29	1.02		
Default Tariff	998	NHH	CG3	21.66	1.41			11.29	1.02		
Non-Dom WE (PC3)	202	NHH	CG3	21.66	1.41			11.29	1.02		
Non-Dom UR (PC3) WO	223	NHH	CG3	21.66	1.41			11.29	1.02		
Default Tariff WO	999	NHH	CG3	21.66	1.41			11.29	1.02		
Non-Dom WE (PC3) WO	222	NHH	CG3	21.66	1.41			11.29	1.02		
Non-Dom Restricted (PC4)	204	NHH	CG4	22.89	1.41	0.11		12.79	0.99	0.15	
Non-Dom WE (PC4)	201	NHH	CG4	22.89	1.41	0.11		12.79	0.99	0.46	
Non-Dom Restricted (PC4) WO	224	NHH	CG4	22.89	1.41	0.11		12.79	0.99	0.15	
Non-Dom WE (PC4) WO	221	NHH	CG4	22.89	1.41	0.11		12.79	0.99	0.46	
Non-Dom OP (PC4)	205	NHH	CG4	3.07	0.11			3.95	0.23		
Non-Dom OP (PC4) WO	225	NHH	CG4	3.07	0.11			3.95	0.23		
NHH 15-50kW (PC5-8)	257	NHH	CG5	69.30	0.99	0.16		55.11	1.03	0.16	
NHH 15-50kW SR (PC5-8)	256	NHH	CG5	69.30	0.98			55.11	0.81		
NHH LVNet <100kW (PC5-8)	268	NHH	CG5	69.30	0.99	0.16		55.11	1.03	0.16	
NHH LVNet <100kW SR (PC5-8)	267	NHH	CG5	69.30	0.98			55.11	0.81		
NHH LVSub <100kW (PC5-8)	265	NHH	CG5	69.30	0.99	0.16		55.11	1.03	0.16	
NHH LVSub <100kW SR (PC5-8)	264	NHH	CG5	69.30	0.98			55.11	0.81		
NHH 15-50kW (PC5-8) WO	277	NHH	CG5	69.30	0.99	0.16		55.11	1.03	0.16	
NHH 15-50kW SR (PC5-8) WO	276	NHH	CG5	69.30	0.98			55.11	0.81		
NHH LVNet <100kW (PC5-8) WO	288	NHH	CG5	69.30	0.99	0.16		55.11	1.03	0.16	
NHH LVNet <100kW SR (PC5-8) WO	287	NHH	CG5	69.30	0.98			55.11	0.81		
NHH LVSub <100kW (PC 5-8) WO	285	NHH	CG5	69.30	0.99	0.16		55.11	1.03	0.16	
NHH LVSub <100kW SR (PC5-8) WO	284	NHH	CG5	69.30	0.98			55.11	0.81		
NHH HVStd <100kW (PC5-8)	304	NHH	CG6	480.39	0.22	0.12		53.97	0.54	0.08	
NHH HVStd <100kW SR (PC5-8)	303	NHH	CG6	480.39	0.21			53.97	0.44		
NHH HVStd <100kW (PC5-8) WO	324	NHH	CG6	480.39	0.22	0.12		53.97	0.54	0.08	
NHH HVStd <100kW SR (PC5-8) WO	323	NHH	CG6	480.39	0.21			53.97	0.44		
HH LV Std <100kW	253	HH	CG7	189.58	0.26	0.05	3.26	416.07	0.26	0.04	4.08
HH LV Std >100kW	251	HH	CG7	189.58	0.26	0.05	3.26	416.07	0.26	0.04	4.08
HH LV Site Specific	655	HH	CG7	95.31	0.85	0.10		416.07	0.26	0.04	4.08
HH LV Site Specific	666	HH	CG7	329.41	0.65	0.10		416.07	0.26	0.04	4.08
HH HV Std >100kW	301	HH	CG8	1007.11	0.18	0.05	3.26	1465.02	0.10	0.02	2.76
HH HV Site Specific	610	HH	CG8	242.46	0.15	0.03	3.26	1465.02	0.10	0.02	2.76
HH HV Site Specific	674	HH	CG8	245.85	0.25	0.09	1.32	1465.02	0.10	0.02	2.76
HH HV Site Specific	677	HH	CG8	667.90	0.18	0.10		1465.02	0.10	0.02	2.76
UMS 24 Hour	500	UMS	CG9	11.93	1.03			83.47	0.64		
UMS Dusk to Dawn	501	UMS	CG9	11.93	1.03			83.47	0.64		
UMS Half Night Pre-Dawn	502	UMS	CG9	11.93	1.03			83.47	0.64		
UMS Dawn to Dusk	503	UMS	CG9	11.93	1.03			83.47	0.64		
UMS Site Specific 1	550	UMS	CG9	11.93	1.03			83.47	0.64		
UMS Site Specific 2	551	UMS	CG9	11.93	1.03			83.47	0.64		
UMS Site Specific 3	552	UMS	CG9	11.93	1.03			83.47	0.64		

Appendix 4 – NEDL - effects on the average annual charges

Tariff Description	LLF	Market	Customer group	Number of customers	2006/07 charges	500MW network model
Dom UR (PC1)	1	NHH	CG1	1,132,874	£64	£69
Dom UR PP (PC1)	5	NHH	CG1	177,205	£60	£64
Dom UR (PC1) WO	21	NHH	CG1	0	£0	£0
Dom UR PP (PC1) WO	25	NHH	CG1	0	£0	£0
Dom Restricted (PC2)	2	NHH	CG2	95,197	£66	£72
Dom Restricted PP (PC2)	6	NHH	CG2	14,209	£64	£70
Dom Restricted (PC2) WO	22	NHH	CG2	0	£0	£0
Dom Restricted PP (PC2) WO	26	NHH	CG2	0	£0	£0
Dom Restr OP Hrs (PC2&4)	8	NHH	CG2	4,238	£29	£27
Dom OP (PC2)	12	NHH	CG2	26,678	£9	£28
Dom Restr OP Hrs (PC2&4) WO	28	NHH	CG2	0	£0	£0
Dom OP (PC2) WO	32	NHH	CG2	0	£0	£0
Non-Dom UR (PC3)	203	NHH	CG3	71,697	£256	£170
Default Tariff	998	NHH	CG3	278	£98	£55
Non-Dom WE (PC3)	202	NHH	CG3	1,550	£276	£184
Non-Dom UR (PC3) WO	223	NHH	CG3	0	£0	£0
Default Tariff WO	999	NHH	CG3	14	£1,984	£1,421
Non-Dom WE (PC3) WO	222	NHH	CG3	0	£0	£0
Non-Dom Restricted (PC4)	204	NHH	CG4	13,409	£282	£192
Non-Dom WE (PC4)	201	NHH	CG4	2,397	£230	£206
Non-Dom Restricted (PC4) WO	224	NHH	CG4	0	£0	£0
Non-Dom WE (PC4) WO	221	NHH	CG4	3	£771	£905
Non-Dom OP (PC4)	205	NHH	CG4	1,138	£27	£47
Non-Dom OP (PC4) WO	225	NHH	CG4	0	£0	£0
NHH 15-50kW (PC5-8)	257	NHH	CG5	5,717	£1,024	£1,005
NHH 15-50kW SR (PC5-8)	256	NHH	CG5	9,142	£963	£785
NHH LVNet <100kW (PC5-8)	268	NHH	CG5	669	£1,162	£1,149
NHH LVNet <100kW SR (PC5-8)	267	NHH	CG5	1,614	£963	£786
NHH LVSub <100kW (PC5-8)	265	NHH	CG5	228	£1,687	£1,697
NHH LVSub <100kW SR (PC5-8)	264	NHH	CG5	176	£1,524	£1,247
NHH 15-50kW (PC5-8) WO	277	NHH	CG5	0	£0	£0
NHH 15-50kW SR (PC5-8) WO	276	NHH	CG5	0	£0	£0
NHH LVNet <100kW (PC5-8) WO	288	NHH	CG5	160	£2,078	£2,104
NHH LVNet <100kW SR (PC5-8) WO	287	NHH	CG5	8	£2,544	£2,087
NHH LVSub <100kW (PC 5-8) WO	285	NHH	CG5	5	£4,287	£4,406
NHH LVSub <100kW SR (PC5-8) WO	284	NHH	CG5	8	£3,803	£3,124
NHH HVStd <100kW (PC5-8)	304	NHH	CG6	51	£2,076	£903
NHH HVStd <100kW SR (PC5-8)	303	NHH	CG6	8	£2,047	£807
NHH HVStd <100kW (PC5-8) WO	324	NHH	CG6	0	£0	£0
NHH HVStd <100kW SR (PC5-8) WO	323	NHH	CG6	0	£0	£0
HH LV Std <100kW	253	HH	CG7	257	£1,432	£2,358
HH LV Std >100kW	251	HH	CG7	3,506	£5,571	£7,260
HH LV Site Specific	655	HH	CG7	2	£810	£2,708
HH LV Site Specific	666	HH	CG7	2	£1,217	£2,307
HH HV Std >100kW	301	HH	CG8	680	£29,771	£25,001
HH HV Site Specific	610	HH	CG8	1	£179,935	£146,643
HH HV Site Specific	674	HH	CG8	1	£12,942	£30,569
HH HV Site Specific	677	HH	CG8	15	£2,522	£8,516
UMS 24 Hour	500	UMS	CG9	625	£353	£496
UMS Dusk to Dawn	501	UMS	CG9	571	£3,916	£2,699
UMS Half Night Pre-Dawn	502	UMS	CG9	63	£392	£520
UMS Dawn to Dusk	503	UMS	CG9	8	£1,621	£1,280
UMS Site Specific 1	550	UMS	CG9	154	£201	£402
UMS Site Specific 2	551	UMS	CG9	137	£1,660	£1,304
UMS Site Specific 3	552	UMS	CG9	2	£6,654	£4,393

Appendix 5 – YEDL - illustrative charges

Tariff Description	LLF	Market	Customer group	2006/07 charges				Pricing model			
				Fixed charge (p/cust/day)	Unit charge 1 (p/kWh)	Unit charge 2 (p/kWh)	Availability charge (p/kVA/day)	Fixed charge (p/cust/day)	Unit charge 1 (p/kWh)	Unit charge 2 (p/kWh)	Availability charge (p/kVA/day)
Dom UR (PC1)	100	NHH	CG1	8.19	0.69			4.89	1.05		
Dom UR PP (PC1)	101	NHH	CG1	8.19	0.69			4.89	1.05		
Dom UR (PC1) WO	400	NHH	CG1	8.19	0.69			4.89	1.05		
Dom UR PP (PC1) WO	401	NHH	CG1	8.19	0.69			4.89	1.05		
Dom Restricted (PC2)	120	NHH	CG2	8.26	0.80	0.12		5.83	1.36	0.20	
Dom Restricted PP (PC2)	121	NHH	CG2	8.26	0.80	0.12		5.83	1.36	0.20	
Dom Restricted (PC2) WO	402	NHH	CG2	8.26	0.80	0.12		5.83	1.36	0.20	
Dom Restricted PP (PC2) WO	403	NHH	CG2	8.26	0.80	0.12		5.83	1.36	0.20	
Dom OP (PC2)	111	NHH	CG2		0.12			2.35	0.12		
Dom Heat Plus (PC2)	130	NHH	CG2		0.12			2.35	0.12		
Dom Heat Plus PP (PC2)	131	NHH	CG2		0.12			2.35	0.12		
Non-Dom UR (PC3)	240	NHH	CG3	21.28	0.69			13.98	1.10		
Non-Dom UR PP (PC3)	241	NHH	CG3	21.28	0.69			13.98	1.10		
Non-Dom UR (PC3) WO	404	NHH	CG3	21.28	0.69			13.98	1.10		
Non-Dom UR PP (PC3) WO	405	NHH	CG3	21.28	0.69			13.98	1.10		
Default Tariff	999	NHH	CG3	21.28	0.69			13.98	1.10		
Non-Dom Restricted (PC4)	246	NHH	CG4	21.54	0.80	0.12		18.87	1.05	0.16	
Non-Dom Restricted PP (PC4)	249	NHH	CG4	21.54	0.80	0.12		18.87	1.05	0.16	
Non-Dom Restricted (PC4) WO	406	NHH	CG4	21.54	0.80	0.12		18.87	1.05	0.16	
Non-Dom Restricted PP (PC4) WO	407	NHH	CG4	21.54	0.80	0.12		18.87	1.05	0.16	
Non-Dom WE (PC3&4)	250	NHH	CG4	21.54	0.80	0.12		18.87	1.05	0.56	
Non-Dom Two Rate Terms (PC4)	275	NHH	CG4	21.54	0.80	0.12		18.87	1.05	0.60	
Non-Dom OP (PC4)	214	NHH	CG4		0.12			2.80	0.12		
Non-Dom Grain Dryer (PC4)	268	NHH	CG4		0.80			2.80	0.12		
NHH LVStd >100kW (PC5-8)	280	NHH	CG5	286.15	0.70	0.12		87.51	1.15	0.17	
NHH LVStd >100kW (PC5-8) WO	408	NHH	CG5	286.15	0.70	0.12		87.51	1.15	0.17	
NHH LVStd <100kW (PC5-8)	290	NHH	CG5	286.15	0.70	0.12		87.51	1.15	0.17	
NHH LVStd <100kW (PC5-8) WO	409	NHH	CG5	286.15	0.70	0.12		87.51	1.15	0.17	
NHH LVStd <100kW DM3 (PC5-8)	287	NHH	CG5	286.15	0.69			87.51	0.94		
NHH HV Std <100kW (PC5-8)	580	NHH	CG6	1079.30	0.23	0.12		44.82	0.51	0.08	
NHH HV Std <100kW (PC5-8) WO	410	NHH	CG6	1079.30	0.23	0.12		44.82	0.51	0.08	
HH Non-Dom UR	244	HH	CG7	21.65	0.69			279.13	0.18		4.13
HH Non-Dom Restricted	248	HH	CG7	21.65	0.80	0.12		279.13	0.22	0.04	4.13
HH Non-Dom WE	257	HH	CG7	21.65	0.80	0.12		279.13	0.22	0.04	4.13
HH LV Std >100kW	281	HH	CG7	246.33	0.53	0.07	3.31	279.13	0.22	0.04	4.13
HH LV Std <100kW	291	HH	CG7	246.33	0.53	0.07	3.31	279.13	0.22	0.04	4.13
HH LV Sub >100kW	471	HH	CG7	246.33	0.53	0.07	2.51	279.13	0.22	0.04	3.63
HH LV Sub (No Discount)	472	HH	CG7	246.33	0.53	0.07	3.31	279.13	0.22	0.04	4.13
HH LV Std >100kW DM3	297	HH	CG7	246.33	0.52		3.31	279.13	0.18		4.13
HH HV Std >100kW	581	HH	CG8	454.71	0.22	0.07	3.31	1127.65	0.09	0.02	2.76
HH HV Sub >100kW	685	HH	CG8	454.71	0.22	0.07	2.51	1127.65	0.09	0.02	2.26
HH HV Sub (No Discount)	686	HH	CG8	454.71	0.22	0.07	3.31	1127.65	0.09	0.02	2.76
HH HV - Kirklees Stadium	500	HH	CG8	454.71	0.22	0.07	3.31	1127.65	0.09	0.02	2.76
HH HV - Sugarwell Court Student Residences	501	HH	CG8	454.71	0.22	0.07	2.36	1127.65	0.09	0.02	2.16
HH HV - Kirkstall Brewery Student Residences	502	HH	CG8	454.71	0.22	0.07	2.36	1127.65	0.09	0.02	2.16
HH HV - Sulzer 11 kV Supply	741	HH	CG8	8037.36	0.22	0.07		8373.83	0.09	0.02	
HH HV - Sulzer 11kV Supply	742	HH	CG8	8037.36	0.22	0.07		8373.83	0.09	0.02	
NHH UMS - Unauditable Inv (PC1&8)	812	UMS	CG9	19.32	1.08			180.73	0.97		
NHH UMS - Auditable Inv (PC1&8)	912	UMS	CG9	19.32	1.03			180.73	0.92		
HH UMS - Unauditable Inv	813	UMS	CG9	19.32	1.02			180.73	0.97		
HH UMS - Auditable Inv	913	UMS	CG9	19.32	0.97			180.73	0.92		

Appendix 6 – YEDL - effects on the average annual charges

Tariff Description	LLF	Market	Customer group	Number of customers	2006/07 charges	500MW network model
Dom UR (PC1)	100	NHH	CG1	1,639,286	£58	£61
Dom UR PP (PC1)	101	NHH	CG1	218,332	£60	£63
Dom UR (PC1) WO	400	NHH	CG1	0	£0	£0
Dom UR PP (PC1) WO	401	NHH	CG1	0	£0	£0
Dom Restricted (PC2)	120	NHH	CG2	144,092	£64	£78
Dom Restricted PP (PC2)	121	NHH	CG2	19,388	£63	£77
Dom Restricted (PC2) WO	402	NHH	CG2	0	£0	£0
Dom Restricted PP (PC2) WO	403	NHH	CG2	0	£0	£0
Dom OP (PC2)	111	NHH	CG2	20,553	£6	£15
Dom Heat Plus (PC2)	130	NHH	CG2	1,086	£9	£17
Dom Heat Plus PP (PC2)	131	NHH	CG2	85	£9	£17
Non-Dom UR (PC3)	240	NHH	CG3	101,202	£188	£227
Non-Dom UR PP (PC3)	241	NHH	CG3	136	£127	£130
Non-Dom UR (PC3) WO	404	NHH	CG3	2	£129	£132
Non-Dom UR PP (PC3) WO	405	NHH	CG3	0	£0	£0
Default Tariff	999	NHH	CG3	54	£202	£249
Non-Dom Restricted (PC4)	246	NHH	CG4	19,346	£237	£277
Non-Dom Restricted PP (PC4)	249	NHH	CG4	107	£198	£226
Non-Dom Restricted (PC4) WO	406	NHH	CG4	0	£0	£0
Non-Dom Restricted PP (PC4) WO	407	NHH	CG4	0	£0	£0
Non-Dom WE (PC3&4)	250	NHH	CG4	10,025	£253	£402
Non-Dom Two Rate Terms (PC4)	275	NHH	CG4	545	£107	£128
Non-Dom OP (PC4)	214	NHH	CG4	3,587	£12	£23
Non-Dom Grain Dryer (PC4)	268	NHH	CG4	93	£153	£34
NHH LVStd >100kW (PC5-8)	280	NHH	CG5	511	£2,145	£2,119
NHH LVStd >100kW (PC5-8) WO	408	NHH	CG5	0	£0	£0
NHH LVStd <100kW (PC5-8)	290	NHH	CG5	8,260	£1,836	£1,614
NHH LVStd <100kW (PC5-8) WO	409	NHH	CG5	0	£0	£0
NHH LVStd <100kW DM3 (PC5-8)	287	NHH	CG5	1,446	£1,630	£1,113
NHH HV Std <100kW (PC5-8)	580	NHH	CG6	33	£4,257	£817
NHH HV Std <100kW (PC5-8) WO	410	NHH	CG6	0	£0	£0
HH Non-Dom UR	244	HH	CG7	4	£4,426	£4,665
HH Non-Dom Restricted	248	HH	CG7	2	£1,250	£3,242
HH Non-Dom WE	257	HH	CG7	2	£934	£3,148
HH LV Std >100kW	281	HH	CG7	3,342	£5,604	£5,185
HH LV Std <100kW	291	HH	CG7	2,149	£5,374	£4,788
HH LV Sub >100kW	471	HH	CG7	71	£8,865	£8,172
HH LV Sub (No Discount)	472	HH	CG7	0	£0	£0
HH LV Std >100kW DM3	297	HH	CG7	44	£3,552	£3,254
HH HV Std >100kW	581	HH	CG8	1,730	£23,195	£19,066
HH HV Sub >100kW	685	HH	CG8	49	£108,069	£78,073
HH HV Sub (No Discount)	686	HH	CG8	2	£28,787	£22,205
HH HV - Kirklees Stadium	500	HH	CG8	1	£23,077	£19,911
HH HV - Sugarwell Court Student Residences	501	HH	CG8	1	£15,572	£15,685
HH HV - Kirkstall Brewery Student Residences	502	HH	CG8	1	£33,236	£30,021
HH HV - Sulzer 11 kV Supply	741	HH	CG8	1	£36,536	£33,550
HH HV - Sulzer 11kV Supply	742	HH	CG8	1	£35,287	£33,107
NHH UMS - Unauditable Inv (PC1&8)	812	UMS	CG9	971	£1,690	£2,109
NHH UMS - Auditable Inv (PC1&8)	912	UMS	CG9	0	£0	£0
HH UMS - Unauditable Inv	813	UMS	CG9	0	£0	£0
HH UMS - Auditable Inv	913	UMS	CG9	11	£118,059	£112,193

Appendix 7 – Revised wording for section 3 of the UoS methodology statement

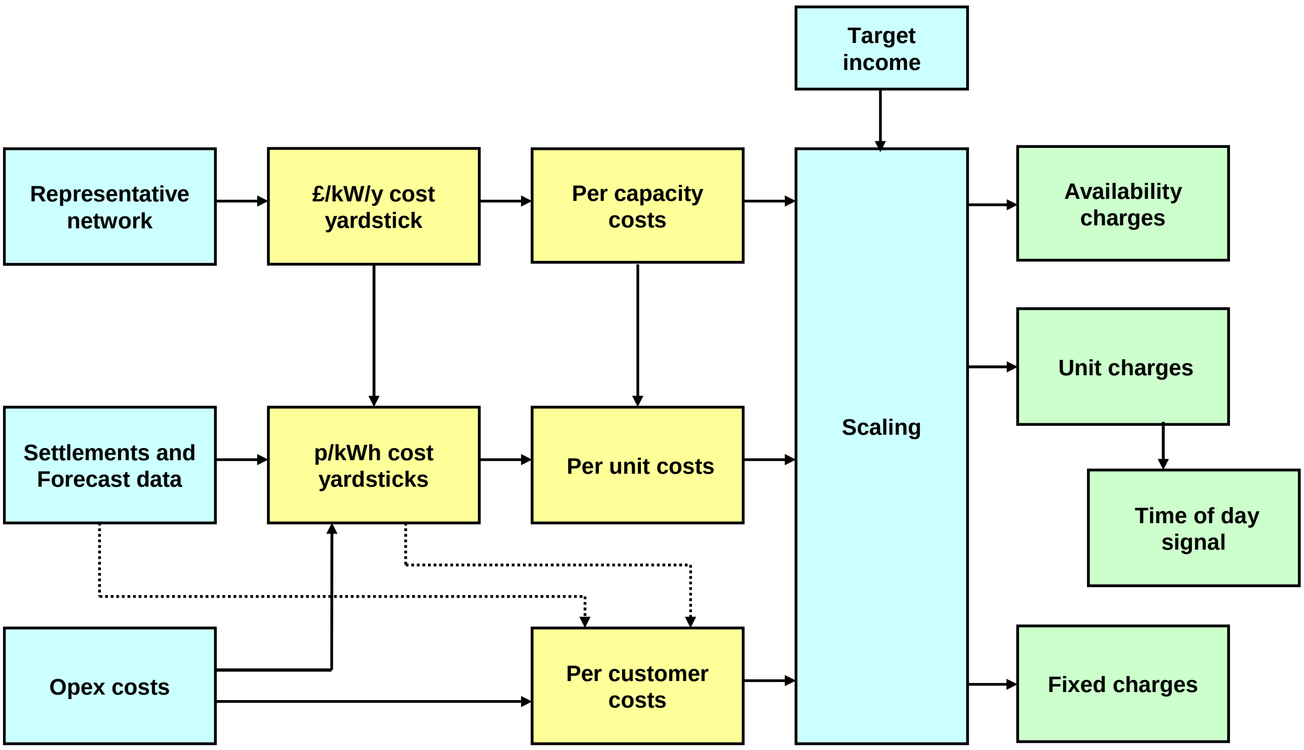
3 Methodology for calculating general LV and HV demand charges

3.1 Overview of the model

The pricing model for low voltage (LV) and high voltage (HV) connected customers is based on the long-run marginal costs of the network and the operating costs identified from our annual price control review information submissions to Ofgem. The model is a customised version of the EA Technology cost allocation spreadsheet developed in the late 1990s and adopts the same principles as those used in the original Electricity Council distribution reinforcement model (DRM) developed in the 1980s. Implementation of the model is via a newly developed Microsoft Excel spreadsheet designed to clearly and logically display the inputs, calculations and outputs.

The basic principle of the model is to share the asset costs of the representative incremental network between customers by reference to their contribution to the demand that necessitates the assets. The outputs from the model are the cost per kW (or kVA) of maximum demand at each voltage and transformation level (cost yardsticks). These are used to derive yardstick unit charges and availability charges which are used in conjunction with the fixed charge element. These are then scaled to create tariffs that will recover target income.

The following figure shows a high-level overview of the end-to-end process.



The model then uses the settlements and forecast information to convert the £/kW yardsticks into p/kWh values.

3.2 Functionality of the model

The functionality of the model can be categorised into the key areas listed below

- Asset information;
- Settlements and forecast information;
- Operating cost data; and
- Calculation of yardstick charges.

3.2.1 Asset information

The model utilises a 500MW representative network, based on the topography and demographics of the YEDL [NEDL] region. The model represents the way in which we would provide a network to meet the requirements of typical demand and topography if we were to build it today using the latest equipment, technologies and network design standards. The model only includes assets that would be paid for by YEDL [NEDL] and takes account of assets paid for by customers under current connection policy.

Each asset is costed at its modern equivalent asset (MEA) value. It is then annualised using an annuity factor, based on a 6.9% rate of return and twenty-year asset life.

The model anticipates that there will be a natural diversity between the demand of individual customers connected at each voltage level and the maximum demand that must be met by the network at that voltage.

Utilising this data and information on electrical losses, a £/kW yardstick for each voltage and transformation level is calculated.

The output is a table similar to the one below. (It should be noted that the figures in the table below are for illustrative purposes only).

Connection	Network level						
	132kV	132/33	33kV	33/11kV	11kV	11kV/LV	LV
at LV	5.82	4.08	1.88	5.16	12.79	3.69	2.75
at HV	5.54	3.88	1.79	4.38	10.86		
at EHV	5.47	3.61	1.66				

3.2.2 Settlements and forecast data

The model utilises a number of customer groups. In order to calculate the contribution of each group to system maximum demand, a large amount of up-to-date settlement and forecast information is required, the majority of which is based on billing system outputs, namely:

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

Utilising the above information, the contribution of the group's demand at the time of system maximum demand (SMD) is calculated by multiplying the annual consumption, coincidence factor and losses, then dividing this by the load factor.

$$\text{SMD including losses (kW)} = \frac{1{,}000 \times \text{Annual consumption} \times \text{Coincidence factor} \times (1 + \text{losses})}{\text{Load factor}}$$

For example a customer group with an annual consumption of 20,000GWh/y, a coincidence factor of 0.8421, a loss factor of 8.89% and a load factor of 3,494 kWh/y/kW yields:

$$\text{SMD including losses (kW)} = \frac{1{,}000 \times 20{,}000 \times 0.8421 \times (1 + 0.0889)}{3{,}494}$$

$$= 5{,}249 \text{ kW}$$

3.2.3 Operating costs

The operating cost (opex) information within the model identifies the costs of serving customers that are not dependent on network investment. The model utilises our annual price control review information submissions to Ofgem since these costs are believed to offer a reasonable approximation to the long-run marginal cost for this element and the data is readily available.

3.2.4 Calculation of yardstick charges

The outputs of the model are the cost per unit yardstick for all customer groups at each of the voltage levels and, also, the total network yardstick (p/kWh) for each group.

3.2.4.1 Calculation of unit cost yardsticks

The unit cost yardsticks are calculated by taking the outputs of the asset data (i.e. £/kW yardstick values) and combining them with the settlements data to obtain a p/kWh yardstick value.

The conversion is undertaken for each network and transformation level, as follows:

$$\frac{\textbf{£/kW/y cost yardstick x coincidence factor}}{\textbf{Load factor (kWh/y/kW)}}$$

In addition to the yardstick values calculated above, an additional amount is allocated to reflect exit charges. This is done by allocating total annual exit charges on a pro-rata basis to the calculated SMD, then dividing the result by the forecast consumption to give a p/kWh value.

3.2.4.2 Calculation of fixed-cost yardsticks

The fixed-cost yardsticks are calculated by taking the annual operating costs and categorising them into three areas (direct activities, indirect activities and non-activity based costs), the majority of which are recovered on a pence per day basis so that the costs can easily be identified and quantified. The exception is exit charges which, in line with normal DRM practice, are recovered on a p/kWh basis. The list below gives more details on how the operating costs are treated:

- NGET exit charges – built into the p/kWh yardsticks on a pro rata basis in relation to the amount of capacity utilised by each customer group (i.e. calculated SMD including losses):
- Asset-related opex – built into the p/day yardsticks on a pro rata basis in relation the outputs of the representative network model (i.e. on a capacity basis in relation to the asset-generated p/kWh yardstick cost values); and
- Non-asset related opex – also built into the p/day yardsticks, only this time on a customer numbers basis.

3.2.4.3 Calculation of capacity cost yardsticks

The availability charge is derived from the yardstick values in £/kW/y for each level of the 500MW model network. These charges are only applicable to those customer groups whose metering has the required functionality and where the data can be processed via the settlement/billing systems.

A reduction factor is applied to allow the capacity cost yardsticks to be calculated using the following cost elements:-

- The capital cost of the network at the connection level;
- The cost at the transformation level above; and
- 20% of the cost of the level above that.

Coincidence factors are then applied, giving the ratio of the peak load to the system peak at the connection level and the levels above.

$$\text{Charge } \pounds/\text{kW/y} = \text{Network costs} \times \text{Reduction factor} \times \text{Coincidence factor}$$

The £/kW/y charge is then converted to a £/kVA/y charge by applying a power factor of 0.95.

3.2.5 Final yardstick charges including scaling

Once all the yardsticks for each customer group have been determined the various elements of the charge are scaled to ensure recovery of target income.

Where scaling is applied we have used the fixed multiplier approach which:

- Maintains proportional relativity between customer groups;
- Is simple to apply across multiple tariff elements; and
- Is transparent in its application.

In order to achieve target income a scaling factor is applied to the fixed and unit yardstick values.

In addition, for customers whose metering functionality allows, an availability charge can be applied. In order to avoid discrimination, maintain cost reflectivity and avoid double counting, the unit p/kWh yardstick values (calculated above) are reduced in line with the level of income recovered from the capacity charges.

The model also facilitates the scaling of capacity charges, again using a fixed multiplier, in order to avoid negative unit charges and vary the strength of the pricing message being sent.

3.3 Tariff model

The yardstick charges from the pricing model (discussed above) are then utilised in the tariff model to determine the prices that are published in the condition 4A statement.

The model utilises monthly customer numbers, availability and consumption forecasts (split by day and night) for each tariff. This information is combined with the yardstick charges from the pricing model to determine the total income to be recovered from each tariff.

The charges allocated to individual tariffs are dependent on the type of metering installed. Tariffs in the non-half hourly (NHH) market are billed through the Supercustomer system and include a fixed charge (p/cust/day) and unit-related charge (p/kWh). Tariffs in the half-hourly market (HH) include a fixed charge (p/cust/day), a unit-related charge (p/kWh) and an availability charge (p/kVA/day) based on the agreed connection capacity.

In the main the population of charges in the tariffs model will be a straightforward lift from the pricing model. However, where we have multi-rate tariffs a decision is taken as to whether or not it is appropriate to send a time-of-day signal. If deemed appropriate the single yardstick unit rate value will be adjusted to send the time-of-day signal (i.e. if the night rate drops, the day rate must increase to ensure that the overall amount of income recovered from the tariff matches that generated from applying a single rate.) This enables us to encourage efficient use of the network at the times of day, or year, when the system is less heavily loaded.

The maximum annual load profile per half-hour provides an indication of the size of the signal to send. This is achieved by utilising the minimum half-hourly maximum demand as our baseline and then considering the ratio of the variances from this baseline to the average maximum demand for the time periods in respect of which we wish to send a signal.