WESTERN POWER DISTRIBUTION

Serving the South West and Wales
Gwasanaethu'r De Orllewin a Chymru

Responses to Consultation on potential changes to the Use Of System Methodology

(July 2006 consultation)

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Thursday, 24th August 2006

Simon Yeo
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Western Power Distribution

Via e-mail: wpdpricing@westernpower.co.uk

Dear Simon,

Reference: Consultation on potential changes to the Use of System Methodology, July 2006

Thank you for the opportunity to comment on the above consultation. This letter represents the views of the Centrica Group excluding Centrica Storage Ltd. This response is non-confidential and may be published on the WPD website.

As a general observation both of this process and that being carried out by the ENA, we do have some concerns over the approach taken by the DNOs. With particular reference to section 4 of the WPD consultation, it seems to us that the treatment of consultation responses from other stakeholders is often rather cursory. In order to ensure a fully open and effective process which maximises wider industry “sign on” to its conclusions, we would encourage WPD and other distributors to provide further reasoned argument and justification in cases where they do not consider it appropriate to take other stakeholder responses on board.

As we have previously commented, we believe that changes to the existing methodology should be minimised where possible and the simplest, most transparent, stable & predictable methodology should be chosen unless there are clear and substantiated benefits from a more complex approach. This should involve, for example, setting efficiency gains from greater cost-reflectivity against industry implementation costs and the impact of reduced transparency/predictability of charges. In our view the LRIC methodology is significantly more complex than that already in use and hence it does cause us some concerns. However, we consider the approach of applying a methodology generating site specific charges only to EHV sites (or those close to/in excess of 10 MW of demand), but retaining the simpler DRM model for all other voltages, might be a reasonable compromise. We base this view on the presumption that more efficient investment/location decisions in the EHV segment are most likely to justify the greater complexity, while industry implementation costs are likely to be relatively modest in respect of a more limited number of larger EHV sites. However, the case for this should be more clearly demonstrated by WPD and other DNOs prior to moving forward on this issue.

In respect of revenue reconciliation, we are in agreement that the mechanism chosen for scaling should maintain any signals generated by the underlying methodology. The approach of using a multiplier rather than a straight adder would seem to be equitable, taking into account the potential difficulties associated with generation in particular when an adder is applied to smaller charges.

We agree that if there is no proposal to change the tariff structures as a result of the methodology change, then supplier systems should not be affected. We would, however, ask that the potential tariff charges are evaluated at an early stage to confirm that the tariff structures would not require changing as a result of this once the new methodology has been in place for a year or two. If this testing shows that there is risk of a change being needed to the tariff structures, it would be best to evaluate this change early given the associated supplier costs.

Having reviewed the Methodology Statement, we believe that as far as we can tell, the proposed changes do reflect the methodology as proposed in the consultation document.

In response to the questions raised under chapter 6, as noted above we consider that the LRIC, whilst it could be considered likely to produce a more cost reflective result than the simpler model, does not better meet the other high level charging principles as identified in Ofgem's May 2005 paper. As such, we believe that a decision to move towards this methodology, even for the relatively small number of sites proposed, is a finely balanced one. In our view, cost reflectivity is only one of five high level principles put forward, and near equal weight should be given to the others.

Moving on to the more detailed material provided in chapter 7, we welcome the fact that indicative charges for customers have been supplied, including a comparison with the actual charges. However, as we have noted in our response to the ENA consultations, we believe that a key comparison is missing, namely the indicative outcome under the different alternative proposals under consideration in that forum.

It may be that full evaluation would lead to the conclusion that the current WPD proposals may be an improvement on the existing WPD process, it is possible that overall, a better result may be achieved under another option.

We believe that a more standardised approach across the industry is likely to prove beneficial, and as such, we are disappointed that WPD has not chosen to await the outcome of the ENA consultation process before initiating a change to its methodology.

The indicative charges provided in the tables in chapter 7 produce some significant variations from the current methodology, and in some cases step changes. We would agree that it may be sensible to consider whether the changes should be phased in over a period to avoid major charging shocks. We would suggest that it would be reasonable to perhaps phase the changes over the rest of this price control period.

At a detailed level, reviewing tables one and five, we are surprised at the levels of increase presented in the Economy 7 Night tariff (Profile Classes 2 & 4), this change (up to 18.7%) seems out of step with other proposed changes, and we would welcome further explanation as to the cause of this step change.

We believe that this step change is related to paragraph 3.4 on page 5. However, we would like further explanation on the coincidence factors, load research and diversity factors used, as we believe that based on the text supplied, this paragraph could be viewed as somewhat subjective.

We hope that these comments have been constructive. Should you wish to discuss any points in more detail, I should be happy to help.

Yours sincerely,

Alison Russell
Senior Regulation Manager, Upstream Energy

Nigel Lloyd
Income & Connection Manager
Western Power Distribution
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31 August 2006

Dear Mr Lloyd

Western Power Distribution (WPD): Consultation on potential changes to the Use Of System Methodology

energywatch welcomes the opportunity to respond to the issues raised by this consultation. This response is non-confidential and we are happy for it to be published on WPD's website.

We maintain that the Distribution Reinforcement Model (DRM) remains the most appropriate methodology by which to determine overall distribution use of system (DUoS) charges going forward. Unless there are overwhelming reasons for applying a different cost reflective approach to DUoS chargeable to a particular sub-set of customers, namely those connected at EHV level, there seems to be limited necessity for potentially disrupting individual users' charges considerably without, at the very least, a period of adjustment. Existing users are not necessarily provided with better cost signals because the methodology has changed. Instead, they may find charges disrupted without the ability to respond other than by leaving potential stranded assets in place by terminating their supply. It is apparent from responses to the January 2006 consultation that there was limited, if any, support for the concept of using a Long Run Incremental Cost (LRIC) methodology for EHV users. Indeed, there was a healthy degree of scepticism and a number of unanswered questions surrounding development and application of a LRIC methodology.

The LRIC methodology which is outlined in the current consultation provides quite a detailed and complex basis for the calculation of DUoS charges. This is one of the main criticisms of the approach, that while it uses incremental cost values at nodal points to determine the reinforcement cost and, thereby, the applicable charges, it does so at the expense of simplicity and predictability which are also key considerations for charging. Directly connected users and suppliers must be able to appreciate how charges have been calculated. We note that WPD believes that its suggested approach does not result in changes to billing systems and processes. However, we are also concerned that consistency of approach may be affected if WPD's methodology differs, for the same type of customer connection, from those in other DNO areas.

A key concern about any locational charging model is that, while UoS charges may affect a user's decision to locate in a particular place, it is only one consideration amongst many. On a fair and consistent basis, we question the extent to which particular users' behaviour is influenced by providing a significant locational element to UoS charges. Site specific charges, to our mind, are a more appropriate, if not perfect, means to apply any locational aspect to a connection to the distribution network. In addition, without a much more sophisticated approach by users and consumers themselves to their network usage, it seems unlikely that changes to UoS charging will by itself influence largely inelastic behaviour by most users.

We note two aspects of the licence obligations on DNOs in respect of their charging methodologies, namely:

- **cost reflectivity "as far as is practicable once implementation costs are taken into account." This obligation does not necessitate increased locational DUoS charging if the cost to users and consumers of implementing changes ultimately proves to be prohibitive. This is why we maintain that the DRM remains relevant; and**

- **facilitate competition in supply and generation. We would argue that users and consumers are relatively inelastic, even for some EHV users, in their ability to respond to more locational DUoS charging and we would therefore question whether the LRIC methodology actually encourages competition.**

We consider that, if WPD proceeds with, and obtains, approval for the change in methodology, there would be a need for transitional arrangements for some EHV users who otherwise could face considerable tariff disturbance. We have no particular approach in mind for these arrangements, however.

Going forward, we will continue to keep these issues under review as and when they are raised, always considering the possible impact on consumers. We are already considering these issues through ENA's consultation process on long-term structure of DUoS charges.

We would appreciate being kept informed of the progress of this consultation and any related issues to enable us to comment as the need arises.

If you do wish to discuss our response further please do not hesitate to contact me on 0191 2212072.

Yours sincerely

Carole Pitkeathley
Head of Regulatory Affairs

REA response to Western Power Distribution Potential Changes to Use of System Methodology

11th August 2006

General

The REA welcomes the opportunity to comment on the proposed WPD System Use of System Charging Methodology. In general the REA is supportive of the move to a more cost-reflective charging methodology and recognises that the proposed Long Run Incremental Cost (LRIC) Approach has the potential to be more cost reflective. We do however have a number of reservations on the application of this methodology as described in the consultation and the draft Charging Methodology Statement. These are addressed below.

Timing of introduction of new methodology

Whilst the REA is supportive of the introduction of more cost reflective charging as soon as possible we are not convinced that the introduction of the proposed methodology from April 2007 would be in the long-term interest of all affected parties. It is accepted that whatever new methodology is introduced ought to be with a view of it enduring for a considerable period. It is therefore more important to make the best choice of methodology than to introduce one a year or two earlier. The reasons that we feel that we can not now endorse the introduction of the described methodology are that it loses the opportunity for another few months or a year of development in a number of important areas described below.

Giving forward-looking, cost-reflective messages

The methodology describes demand charges being derived from peak demand conditions and generation charges being derived from minimum generation conditions. In order to give cost-reflective signals, charges must reflect the costs imposed on the network and also the costs saved by the increment of demand or generation. We do not believe that the proposed methodology necessarily does this.

For example it is possible that an increase in generation at minimum demand conditions accelerates the need for reinforcement, resulting in a positive charge. On the other hand the same increase in generation (as allowed for under P2/6) at times of peak demand may defer the need for reinforcement. In these circumstances it is not cost reflective to base charges only on the advancement of reinforcement under minimum demand conditions whilst not giving a credit for the deferral of reinforcement under peak demand conditions. The complementary argument can be made for demand. We feel that there is a need to investigate this further. We are of course in particular concerned that well located generation should receive credit for any reinforcement that it defers.

Cost reflective charges for hv and lv connectees

The consultation states in paragraph 5.20 that the averaged £/kVA from the EHV model at the 33/11kV level will be used to populate the top levels of the Distribution Reinforcement Model. Seeing as specific ehv LRIC charges have been calculated, it would seem sensible, in the interests of cost-reflectivity, to make use of them (even if a more average approach is used for the lower voltage components of charges for hv/lv connectees.)

There is little information as to how charges for the hv and lv networks for generators are proposed to be calculated. One of the drawbacks of the DRM model is that it does not deal with generation. In general we maintain that it would not be cost reflective to make any charge to generators for the use of such networks whilst these networks are importing under critical conditions i.e. conditions under which reinforcement may be triggered.

Alternative models and advantage of uniformity between DNOs

The REA recognises that it is not a licence requirement for all DNOs to use the same charging methodology. It would nevertheless be of considerable advantage if there was as much commonality as possible. Whilst a few months ago we would have assessed the LRIC methodology the best of those on the table (which can be seen from our response to the second joint DNO consultation) we feel that there may be considerable merit in the methodology being developed by Scottish Power. Whilst we are unable yet to give a view as to which methodology is better (or indeed whether different methodologies are appropriate for different types of network) we feel that a few more months assessing the relative merits of both methodologies may result in an outcome of more commonality between DNOs and also a methodology with a consensus as meeting the objectives more fully.

Conclusion

Whilst the REA thinks that the LRIC methodology has merit we feel it would be premature to introduce the LRIC/DRM methodology as described next April, as there are a number of non-cost-reflective aspects of it that require further investigation. Also allowing some more time for comparison between it and other methodologies increases the chance of the best methodology being adopted more widely.

SP Transmission & Distribution

Your ref

Our ref

Date

25 August 2006

Contact/Extension

Walter Hood
01698 413491

Nigel Lloyd
Income & Connection Manager
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Dear Nigel

WPD Use of System Enduring Charging Methodology 2nd Consultation

Thank you for the opportunity for commenting on your proposed UoS charging methodology changes, which you hope to implement from April 2007.

It is obvious that WPD should bring forward changes, which better meet the relevant Licence objectives. We also have Licence objectives to keep our use of system charging methodology under review, and our comments are primarily prepared, as part of this review, to determine whether the approach you are adopting should be adopted by ourselves. In addition, we also have an inter-DNO connection with WPD (South Wales) and therefore the impact of costs passed through to SP Manweb customers is a concern.

Overall Process

We do not believe that the process and assumptions detailed in paragraphs 5.1 to 5.13 produce long run incremental costs. The underlying characteristics of this approach will result in lower costs for higher forecast growth rates: this is counter intuitive and incorrect. In addition if the actual load growth is zero, which is possible, then there would be no reinforcement requirement, and it is our belief that the model would not generate any charges. In the current environment of rising energy prices and the focus on energy efficiency, zero load growth is a real, if not likely, scenario. The WPD method does not work in these circumstances. Are the 1% demand growth assumptions still realistic in light of recent price increases?

For generation, the methodology takes no account of the benefits provided to network security under P2/6 and does not correctly model generation driven costs as it ignores both fault level and voltage constraints. The asymmetry in demand and generation charges is entirely due to the mathematical formulae used and size of the increments chosen and do not reflect real differences in demand and generation costs.

We do not believe that asset duplication is a good approximation for network reinforcement solutions and even if this is accepted, it is difficult to justify assumption 3. We would agree that for substations, if a transformer is being replaced then using a value of 0.5 of the MEA value is a reasonable approximation, however this is not the case if new substations provided as part of the reinforcement solution. Are new substations never or rarely used for network reinforcement in WPD?

In terms of circuits we cannot see any justification for using multiplier factors of 1.5 and 2 of the MEA value. There can be no difference in the unit cost of the original and additional circuit in MEA terms. There could be increased route lengths but these do not justify the factors that are being quoted.

We do not believe, given the nature of distributed generation, that 1% generation growth and 100kW increments of generation is a suitable method for modelling future generation costs. Generation is added to the network at EHV in much larger increments and, if renewable target are to be achieved, will grow at more than 1% per annum.

Whilst we recognise that methodologies applied to lower voltages networks may require some simplification compared to EHV, the basic principles and concepts should still apply. The fact that the basic methodology is incapable of being used practically at lower voltages questions its suitability for the EHV network also. We also believe that by continuing to use the DRM model, and given the criticisms of its use in the past, it is difficult to understand how its use adequately addresses an enduring long-term solution, it particular its ability to address the impact of distributed generation.

As stated earlier, our main comments are on whether the WPD proposals are suitable for the long-term structure of charges solution. We do not believe they are for the reasons outlined above,
I.e.

- It does not adequately reflect costs
- It does not correctly represent the impact of generation
- It does not consider the lower voltage networks.

We do recognise that WPD have issues with their current methodology resulting in charges to EHV customers being capped below the current charging model outputs. Our concerns are that, using this methodology charges to SP Manweb are expected to increase four-fold.

Our current wheeling agreement is for a capacity of 45MVA with charges of £1.0m. This represents 1.9% of your system maximum demand and 0.6% of your allowed revenue. Your proposal therefore leads to increase in charges to £4.4 million or 2.7% of your allowed revenue. We believe this level of increase is unjustified and not cost reflective and hence we would oppose the implementation of these proposals even as an interim measure if you seek to apply them to our wheeling charges.

Revenue Reconciliation & NGET Charges

Whilst we note your proposed method for revenue reconciliation, this is not consistent with the principles set out by any of the economic advisers consulted by Ofgem, as such an approach is likely to lead to economic inefficiency. It is also our belief that as NGET Exit

Charges provide a significant portion of a DNO's costs, we do not believe that incorporating these costs within the revenue reconciliation process is fair. This would result in EHV customer paying too small a contribution to these costs and LV customers paying too high a contribution. It is our view that these costs should continue to be allocated based on the usage made by the various customer groups of the 132kV system.

Summary

In summary, we do not believe that the WPD approach is the basis for the long-term approach to the structure of charges for the following reasons.

- Assumptions in paragraphs 5.1 to 5.13 do not produce long run incremental costs.
- Growth factor is subjective – zero growth would not generate charges.
- Methodology takes no account of benefits provided under P2/6.
- Methodology ignores fault levels and voltage constraints.
- Asset duplication is not a good approximation for network reinforcement.
- No justification for multiplication factors of 1.5 and 2 of the MEA value.
- 1% Generation growth factor and 100kW increments are not a suitable method for modelling generation costs, given the nature of distributed generation.
- Continued use of DRM is not an enduring long-term solution.
- Proposed increase in Manweb charges unacceptable.

We also do not believe the method gives sufficiently robust outputs for use as an interim measure for your EHV customers and it is doubtful that this method better meets your Licence objectives compared to your current approach. The impact on charges to SP Manweb cannot be justified as a reasonable reflection of forward looking costs.

If you wish to discuss any of the points raised above the please contact me directly.

Yours sincerely

Tony McEntee
Commercial Manager
SP Energy Networks

SSE Energy Supply Limited (SSEESL)

Response to WPD's second consultation on Potential Changes to Use of System Methodology

From: Richard Westoby, Pricing and Forecasting Manager
Date: 21 August 2006

Summary
This is SSEESL's response to the consultation issued electronically by Western Power Distribution (WPD) on 14 July 2006.

We set out our general comments on issues raised by the consultation paper in the following sections, followed by responses to the specific consultation questions.

General Comments on the Consultation

SSEESL remains concerned about the introduction of forward-looking models to drive distribution use of system (DUoS) charges. We recognise that WPD is currently proposing to introduce such a model, based on the long run incremental cost (LRIC) methodology, only for the EHV network. However, we have noted some unexpected changes in the proposed charges for the lower voltages as well. We do not believe that the present proposals form an adequate basis for setting charges until these anomalies and the other concerns discussed below have been addressed. Overall, there are five specific areas that we have comments on.

- Supply business concerns with volatility in DUoS pricing;
- Amount of scaling of modelled output that is required;
- Sensitivity of modelling to input assumptions;
- Transitional arrangements; and
- Treatment of customer contributions.

We comment on each of these in turn below.

<u>Supply Business Concerns with Volatility in DUoS Charges</u>
We are still concerned about the volatility in output prices that will be introduced in moving to dependence on forward-looking economic modelling of DUoS charges – the LRIC approach. The volatility will affect the EHV charges directly as forward-looking views of parameters such as network configuration and forecast use of network capacity change from year to year as well as the actual capacity requirements of the population of EHV users. Increased volatility also appears likely to affect the lower voltage charges, due to the changes proposed for the existing Distribution Reinforcement Model (DRM) and the linkages between this model and the output from the LRIC model.

For an individual EHV system user, it is not just his own behaviour (e.g. increasing or decreasing his own demand) that will affect the DUoS charge he has to pay from year to year. Variations in the input parameters for the model, including capacity increase on decrease decisions by other system users could significantly affect his own charges. This effect is exacerbated if the LRIC model is particularly sensitive to small variations in the input parameters and if the scaling factor on the raw output from the LRIC model is large. We discuss these factors in separate sections below.

Unexpected changes in network pricing are difficult to reflect through in the short term to either mass-market tariffs or business market contractual arrangements. The reasons for this can be seen in the following discussion of pricing arrangements in the two markets.

- In the last couple of years, the primary factor driving supply tariffs has been wholesale energy prices. With all the regulatory notification requirements that a tariff change involves, it is not always straightforward to change tariffs quickly. Variations in DUoS charges are a secondary effect, but still leave the supplier exposed to any increased costs until the next tariff change can be made. If wholesale prices have driven a tariff change in November, for example, a supplier will not necessarily wish to change prices in the following April, the usual point in the year at which DUoS charges change.

- In the business contract market, contracts can be for one or more year's duration – typically up to 3 years with major annual contract rounds undertaken in October. Thus, even with a one-year contract in the business market, a supplier is exposed to the next April's DUoS change. If significant DUoS increases are seen in successive years for a particular contract customer, a supplier is highly likely to be exposed to the full effect of this, at least for a part of his customer base.

The reaction of suppliers to such volatility would be to seek to pass on the DUoS risk to customers via pass-through arrangements where feasible, or to factor an appropriate premium into future prices to cover the perceived risk. End customers would therefore either see higher or more volatile prices themselves. We therefore consider that distribution network operators (DNOs) have a responsibility to both the supply market and end customers to implement any DUoS price changes in as smooth and well sign-posted a manner as possible. We discuss this further under transitional arrangements below.

<u>Scaling of Modelled Output</u>
WPD's paper comments that 15% scaling is required under its existing methodology (implying that about 87% of costs are directly allocated by WPD's current DRM model) whereas there is no comment on the level of scaling required in the current proposals for either the proposed revised DRM or EHV charging. We believe that the scaling involved will be greater and feel strongly that this should be clarified by WPD in presenting their proposals.

DUoS charges will be more volatile if significant scaling is required to reach allowable revenues from charging model outputs, as small changes in underlying model outputs are magnified. In our view, a key measure of the acceptability of any DUoS modelling approach is the extent to which it minimises the amount of scaling required – the more the scaling, the less the intrinsic cost-reflectivity of the underlying model. We are strongly of the view that any scaling required should be no greater than the current order of magnitude. Otherwise, the new charging model cannot be claimed to be cost-reflective and therefore might be inconsistent with the relevant licence obligations.

Sensitivity of modelling to input assumptions

Another feature of DUoS modelling that can give rise to concern is the sensitivity of modelling output, and hence charges to particular customers, to particular assumptions used. As discussed above in relation to the levels of scaling required, we believe that some analysis of the proposed model's sensitivity to input assumptions should be provided by WPD in presenting their proposals. We are also aware of potential problems in LRIC modelling output such as extreme values being produced when certain combinations of circumstances occur. These issues are discussed in a paper by Robin Hodgkins, which is available on the ENA website[1].

All other things being equal, a charging model that produces stable output across a credible range of input parameters will be more acceptable to the market than one where small variations in input produce markedly different results for individual users. Particularly for the more forward–looking inputs, a DNO could expect continual challenge on whether it has chosen the "right" input values and can justify them.

One of the issues we have found with other implementations of forward looking charging models is that it becomes worthwhile for adversely affected users to challenge the use of specific values in the model. Across the two WPD areas, there are 6 customers who would see an increase in their DUoS liability in excess of 100% (£37k to £81k; £51k to £283k; £537k to £1.1m; £153k to £390k; £61k to £523k; £82k to £275k). It may well be that challenges to the basis, parameters and sensitivity of the proposed model are raised from these customers, leading to further uncertainty for all users as, potentially, adjustments are made to the methodology or inputs to address the particular challenges raised.

We see three means of reducing the impact of this issue.

- Firstly, it may be possible to stabilise the output of the LRIC model through the detailed mathematical approach used. There are some ideas about this in the paper by Robin Hodgkins, to which we have referred above. We believe that WPD should take some steps to demonstrate to the market that the model proposed has an intrinsic level of stability against a credible range of inputs.

- Secondly, we believe that all the inputs to the model should be able to be justified from a technical standpoint. It may help promote the credibility and acceptability of the model if some technical information on the derivation of parameters is produced as well as the high-level methodology statement.

- Finally, as discussed in more detail in the following section, we believe that the raw output from the LRIC models should be dampened before being applied to produce actual charges for users. This would have the advantage that charges to users would be set on a smooth transition path, insulated from the extremes of output that may, in fact, be subject to change as input parameters change or the

[1] An Attendee's Comments at the Third ENA Workshop on 12 July 2006.pdf at http://www.energynetworks.org/spring/regulation/cms02/index.aspx

details of the modelling are refined as a result of challenge or debate. It would also allow the signals from the raw model output to be delivered to users in a less painful manner than having an immediate effect on their charges.

Transitional Arrangements

Supply businesses need a well sign-posted, orderly process of change to DUoS charges, in order to be able to factor the changes into their processes for tariff changes and contract tenders, as discussed above.

We strongly recommend that the transition from existing prices to those based on the output from revised DUoS models be tightly controlled. We believe there should be a cap/collar arrangement on the maximum amount by which an individual element of DUoS charges can change from year to year. There is precedent for this in the Ofgem requirement, at the time of the last price control, for generator charges to be subject to a DNO commitment not to change the level of charges by more than 10% from one year to the next.

For the changes proposed by WPD, we suggest a level of 5% for the cap/collar arrangement since suppliers, as discussed above, have exposure to DUoS price changes over periods longer than a year. We are also of the view that, in the early years of an untried modelling approach, there are bound to be unforeseen effects, possible reversals in the direction of the path of individual charges and refinements to the underlying model. If the modelling outputs stabilise over time at a different level from current charges, then capping the percentage of change that can be applied in any one year will allow DUoS charges to converge in the longer term on those different levels of charge. If, in fact, the modelling outputs continue to be volatile, then this approach would allow users to continue to be insulated from the extreme variations. We strongly believe that this would help suppliers to manage the price risk discussed above to the benefit of end users.

The possible alternative of providing a glide-path by phasing in charges over a number of years would not be as helpful, as some changes are very significant in percentage terms, leading to unacceptable annual increments for some charges.

Treatment of customer contributions

It is unacceptable for customers who have paid a contribution to existing assets to be asked to pay charges related to those assets again without some form of compensation. Most, if not all, EHV customers will have contributed to the cost of assets that are covered by the LRIC methodology. This issue highlights a logical flaw in introducing forward-looking charging for a segment of the customer base who have already made commercial decisions to request and finance connection in a different historic context. It is an important gap in the proposed arrangements going forward and we would expect WPD to propose some means of dealing with this issue within the methodology proposals.

Response to Consultation Questions

5.26 As highlighted in 5.10 some of the assets charged for under LRIC may have been part, or entirely paid for by customer contributions as part of the original connection. A potential solution to this would be to move the connection boundary at the next price review for EHV connections and introduce consequential final sums liabilities and capacity guarantees. One consequence of this would be to weaken the incentive for new generators to opt for a cheaper, but less secure, local connection design as they currently see a benefit in lower connection charges. In the interim, should some additional adjustment be made to prices for EHV connections and if so what form should this take?

We have noted our comments on this issue in the section above. Potential solutions are likely to be complex. In our view, it is incumbent on WPD to address the issue of customer contributions directly by providing some analysis and proposals for a solution that could then be the subject of further consultation.

Looking forward, WPD see a potential solution to the above issue in making the connection boundary shallower at the next price review. This, in itself, would not solve the issue about the treatment of existing customers. In our view, there are at least two further factors that suggest the connection boundary should not be changed in the near future.

- The boundary has changed relatively recently at 1 April 2005 in conjunction with the start of the new price control period. In our view, there should be a period of stability while the implications are assessed before further changes are considered.
- We believe it is important to preserve some locational signals for potential connectees within the connection charge. As noted in the consultation paper, the consequence of potential generators not seeing a contribution to reinforcement in their connection charge is likely to be an increased requirement for more expensive "firmer" connections from the DG sector. Hitherto, new generators would have an incentive to accept a less secure local connection as this would mean a lower connection charge. In our view, removing this economic signal at the time of connection would lead to a substantial increase in a DNO's user-driven capital expenditure requirements and therefore higher DUoS charges to customers. We note that this very issue has arisen in transmission charging and is, as yet, unresolved.

The mention above of "consequential final sums liabilities and capacity guarantees" appears to be a reference to the development of arrangements similar to those for transmission level connections where underwriting of connection liabilities is required from users while the connection is built. It occurs to us that such a move may lead to additional resource requirements on distribution businesses that would be needed to manage credit exposures. We are also aware that there are significant issues with the arrangements at transmission level, including the time and effort involved in formal compensation to connected parties for the change in connection boundary.

5.27 The growth rates chosen for both demand and generation are based on projections but based upon historical growth rates. Are these sensible assumptions or *should for example, the growth in generation be linked more directly to government targets for renewable energy?*

We do not believe it is advisable to use government targets for renewables as a proxy for forward-looking DG growth as we expect that DG growth will be variable across the country. It seems sensible to base growth rates in the model on those actually seen by WPD on their network, together with any reasonably expected trend going forward.

On a wider issue, it appears that the assumptions on growth rates might have a significant effect on LRIC model outputs. In this context, we note the comments by Robin Hodgkins, in the previously referenced paper, about the extreme values that can be produced in some circumstances in LRIC modelling depending on the growth rates used and their interaction with the discount rate used in the modelling. We are very uncomfortable with the possibility that there may be significant variations in model outputs and therefore final DUoS charges depending on what may be a fairly arbitrary choice for a forward-looking factor such as growth. We suggest that the model approach is reviewed to stablilise the output against a feasible range of values for growth and other input parameters and that the resulting stability of the model is summarised for users to give confidence in the output values.

5.28 Do you agree that the method of revenue reconciliation is reasonable and fair?

WPD’s proposal for revenue reconciliation involves two main steps: firstly, dividing allowable revenue between the EHV and the lower voltage parts of the market and secondly, scaling the relevant model output to the allowable revenue for each part of the market by uniform percentage scaling.

For the first stage above, WPD provides information on the different outcomes generated by keeping the EHV/other voltage revenue split at current value or adopting an MEA asset valuation split. We agree that there needs to be a method for dividing total allowable revenue between the two models used, for the sake of transparency and a rationale for future variation. However, it is not clear that using an MEA asset valuation for each part of the network as the basis for the ratio is more reasonable than using a historic cost asset valuation. A historic valuation is likely to align more readily with the current split of revenue derived from the existing DRM yardstick-based charging approach and we would expect that any remaining disturbance to charging levels between the two parts of the market would be covered by transitional arrangements as discussed earlier.

The second stage of the process is at the heart of one of our major concerns with the proposed approach, as discussed earlier. Where DUoS modelling has produced a set of charges that cover a large part of the required revenue then final uniform percentage scaling appears a reasonable and pragmatic way to align model output with allowable revenue attributed to each part of the market by the first stage of the process. However, under the current WPD proposals, we still have concerns over the size of the scaling required to reach allowable revenue from the model outputs.

Intrinsically, it appears that the LRIC model output will produce significantly less income than is required and the scaling would be significant, although WPD have not given any values for the scaling required under any scenario. For the modified DRM approach, which WPD comment currently requires scaling of 15%, it is proposed to take some costs out of direct attribution (rates and transmission exit charges) and into the pot of costs covered by scaling. Thus the scaling required for the lower voltage part of the market will also be increased. Overall therefore, the proposed charges have been moved away from a basis which reflected historic costs and instead have become much more arbitrary – scaled significantly to magnify small variations in the output of a forward-looking model, which itself does not bring in enough revenue to cover all the DNO's costs. In our view, this is neither reasonable nor fair.

As a further, related issue, it does appear that the changes to the output of the DRM model are driven by something other than just a change in scaling. From the descriptions in the consultation paper and proposed methodology statement, we understand that the changes to the current DRM model are as follows:

1. Total allowable revenue to be recovered amended due to split discussed above;
2. EHV £/kVA costs at the top levels of the DRM will be adopted from the scaled output of the LRIC approach for the EHV assets;
3. Network rates are removed from the yardsticks and added to the costs to be covered from the final scaling of the DRM output;
4. NGC exit charges are similarly to be recovered from the final DRM scaling rather than being allocated via DRM yardsticks.

Whilst it appears to us that items 1 and 2 should only affect the general level of output DUoS charges rather than the relativity between charges, we are not clear of the effect of items 3 and 4. A review of the tariff level output from the proposed model in tables 1 and 5 shows a systematic relative increase in the charge for night units on profiles 2 and 4, particularly in the South Wales area. We are not clear why this is the case or why it is more cost reflective, given that it appears to result from the decision to remove two types of cost from direct allocation to scaling. In our view, WPD should explain the reasons for the relative changes in output from the revised DRM model and the likely stability of these new charging relativities going forward, as part of the process of consultation with users.

5.29 Do you agree with the proposed treatment of NGC exit charges?
No. We are not clear what the range of feasible options for treatment on NGC exit charges might be. We have a concern that the change proposed would unnecessarily affect the relativity between different DRM level charges as discussed above. Whilst we tend to agree with WPD that allocating NGC exit charges on a pass-through basis at EHV level could create winners and losers depending on whether the exit point is sole-use or shared, we believe there may well be other ways to spread the costs between users. Rather than simply incorporating these costs within the revenue reconciliation, we suggest it might be feasible to spread the total exit charges across connected capacity at EHV level to arrive at a £/kVA figure. This could then be allocated across the individual EHV customers on the basis of their connected capacity, with the balance entering the DRM model in a similar manner to the present DRM approach.

5.30 Do you agree that the draft methodology statement adequately describes the proposed methodology and if not which aspects need further clarification?

No. While the proposed draft methodology statement generally provides a description at a level appropriate for these type of documents, we have raised issues earlier in this response on some aspects of the approach used and on the level of scaling required under the proposed methodology. It is, in our view, too early for the methodology statement to be finalised when there are outstanding issues on the actual methodology itself.

We have a further comment on the wording of the proposed amendments. At the end of the section describing the LRIC methodology, the three components making up the charge for an EHV site are listed. The second of these refers to the cost of the “on-site” sole use connection assets. This raises the question of the treatment of “off site” sole use connection assets and perhaps links with the issues we have raised on the treatment of connection charges already paid in the LRIC modelling approach.

6.8 Views are invited on any aspect of this section [meeting licence objectives]
We have one observation on the content of this section beyond those addressed in response to the question below.

Paragraph 6.6 describes the factors that will vary the LRIC prices. We note that WPD consider that the model is sensitive to changes in the forecast growth in demand and generation. We have discussed the issues around this sensitivity above. However, another feature of this type of model is that a user’s charges will depend just on their own use of the network, but also the decisions of other EHV network users. Such decisions to locate, increase or decrease EHV capacity requirements are likely to have an even greater effect on the charges payable by other network users than the general level of load growth, as the capacity increments involved are much larger. This is one of the features of this type of economic modelling that makes forecasting of DUoS liability more difficult than at present for individual users or their suppliers and contributes to an increased volatility in modelled charges generally.

6.9 Do you agree that the proposed LRIC methodology better meets the licence objectives at EHV than the DRM?
We continue to believe that the proposed approach will not better meet two of the relevant objectives (when compared with the current approach): those relating to cost reflectivity and to facilitation of competition in supply and generation.

On cost reflectivity, We do not consider that WPD has adequately made the case that the LRIC methodology is intrinsically more cost reflective than a DRM (or other) approach to setting EHV charges. If LRIC only brings in a small proportion of the revenue required, then it does not reflect all the costs and if it is looking forward to potential future costs, this is less certain than historic costs actually incurred (and partly paid for by connecting customers).

As discussed earlier in this response, we believe that increasing instability and volatility of network charges has a detrimental effect on suppliers in terms of greater risk and exposure to increases in DUoS charges over a period. Unless adequately controlled, as discussed in the section above on transition arrangements, it will represent an increased burden and risk for suppliers, which will not be helpful to the supply market as a whole. To the extent that suppliers face an increased resource requirement to analyse and manage the risk, this is likely to affect smaller suppliers disproportionately and could therefore have a detrimental effect on supply competition overall. Less stable DUoS charges may also have a detrimental effect on the competition in distribution that is represented by independent or out of area distribution networks, which see host DNO charges as an input cost.

7.3 As with all methodology changes, this change would result in price disturbance and consideration needs to be given to whether transition arrangements are appropriate. Do you believe that transition arrangements would be appropriate and if so in what form?
Yes, we believe transitional arrangements would be appropriate and have set out a proposal for these earlier in this response.

7.4 On a p/kWh basis, the charges calculated for most of the EHV customers are below those that would apply to an HV connected customer. In a few cases the p/kWh charge for an EHV site exceeds the HV p/kWh. Do users believe that this would be an acceptable situation? Or should, for example, a cap at the HV charge level be applied at the EHV level?

We do not believe there is an intrinsic concern with some EHV sites paying more, on a p/kWh basis, than an HV p/kWh charge. The general driver for network costs is capacity, and if some EHV sites have a large capacity but do not use very many units, it would seem reasonable that their charges, looked at on a p/kWh basis, might be higher than some HV p/kWh yardstick. We support cost reflective charges and do not expect that arbitrary constraints such as that suggested should be necessary within the DUoS methodology. However, as discussed above, we are very much in favour of allowing a gradual transition to new charges so that any underlying issues with modelled output can be addressed before users are fully exposed to the new model outputs.

United Utilities Response to WPD Consultation
Potential Changes to the WPD Use of System Methodology

1 Proposed Arrangements

Para 5.5 Incremental approach

We note that the WPD methodology is based on consideration of finite increments of demand. The implication of this is that the calculated "marginal cost" will be dependent on the chosen magnitude of the increment. An alternative approach would be to derive the cost function in algebraic terms, and then derive the marginal cost as the first derivative, with respect to nodal injection, of this cost function.

Para 5.7 AC model

We note that the WPD methodology is based on applying linear scaling to the output from an AC model, taken at a particular set of initial conditions. We have reservations about the applicability of this approach, in particular for the calculation of reactive power charges.

The key feature of the DC model is that it provides a linear output. This allows the principle of superposition to be applied, so that branch flows arising from injections at individual nodes can be considered individually and then added together to calculate the combined effect. This is an essential feature for the attribution of costs arising from a combination of peak branch flows that may be associated with differing sets of initial (contingency) conditions.

In contrast, the output from an AC model is non linear and is therefore dependent on the initial conditions assumed. In particular, it is not true to say that the effect of combining two inputs is equal to the sum of the individual effects, nor do we believe that the reactive flows in the full AC model vary linearly with injection. It may however be possible to develop a simplified linearised model for reactive power flows.

Para 5.6 Application of winter/summer split

The separation of demand and generation scenarios in the way described implies that there is no interaction between demand and generation. It is unclear how this methodology would be applied to, say, a mesh network having both generation-dominated and demand-dominated features in the same geographical area.

Paras 5.10.2 & 5.11 Security Factor

We note that the WPD model incorporates system security factors rather than full contingency analysis, however this approach can be challenged, particularly in the case of meshed networks or where the HV system provides security for the EHV. A more rigorous approach is to rerun model many times to test all contingencies. This has the benefit of identifying the peak flow on each individual asset, whenever it might occur (a particular issue where a network section is dominated by generation).

Para 5.10.3 Future Costs

Most approaches try to establish MEA values, but there are a variety of ways of doing this. Some have suggested using cost projections from the last price control review or the unit costs within that process. It is an interesting question whether to use only the costs of 'load related investment' divided by the extent of load growth or to also allow for replacement investment as well. Our current view is that it is unit costs consistent with network extensions or enhancements that should be used, but we can see the danger of discounting the effects of technological progress in the future. We are also concerned that some parties are looking only at capex, whereas the true incremental costs will also include the future stream of operating expenses triggered by the new investment. The bundle of costs that should be attributed on the basis of the network usage model should therefore include all costs that are triggered by incremental investment, including both direct and indirect opex as well as capex.

Para 5.10.7 Growth assumption

We note that the model uses a single, global, growth rate for demand and generation, and question whether it is possible to apply different growth rates, both for demand and generation, and at each individual node.

Para 5.14 Lower Voltage Networks

We agree that it is appropriate to continue to use the DRM in conjunction with the EHV models for HV/LV networks for the time being, but would be interested to understand further why the lower voltage networks give generically different results from the EHV case.

Para 5.19 Revenue Reconciliation

We understand WPD’s reasoning behind the application of multiplicative rather than additive scaling factors; however although the approach maintains the sign of calculated charges it is not true to say that it maintains the relativity of the cost differential between individual nodes.

Para 5.30 Required Clarifications

The main area requiring clarification is the application of the winter/summer split, in particular to understand how generation and demand charges interact in the WPD model.

2 Proposals versus Licence Obligations

We agree that the LRIC methodology leads to charges which are more reflective of forward looking marginal costs than the DRM, and that it can be used to derive charges for both generation and demand on this basis.

The licence obligations require consideration of the methodology against a wider set of criteria however, and inevitably a trade off between individual objectives. This raises, in our view, two particular issues:

- Our analysis has indicated that the charges derived from a pure LRIC model are dependent on underlying assumptions, in particular the generation and demand growth rates. This can lead to the economic signal being very strong, (ie relatively high prices) which in turn can over-recover costs and therefore require significant scaling to be applied.
- We would like to see further clarification in order to understand how generation and demand charges interact in the WPD model.

3 Impact of Proposed Arrangements on Prices

Application of transition arrangements (for Generation, and for Demand) and/or caps and collars on EHV prices would clearly dampen the economic signal, however they may be appropriate in the context of the expectations of existing users. A particular further example for consideration would be the possibility of capping negative demand charges at zero.

WPD July 2006 Consultation - Responses by e-mail

E.ON UK

We believe these Proposals contradict 3 of Ofgem's key principals in their Structure of Charges Paper released in May 2005; those of Simplicity, Transparency & Predictability for the following reasons;

·Having 2 methodologies with different cost drivers, (one for EHV and one for lower voltage supplies) seems inefficient and sends mixed signals to customers ·WPD's methodology for EHV customers would be inconsistent with the charging principals of each of the other DNOs, which could lead to significantly different costs between distribution networks which is incoherent to the customer ·We remain unconvinced of the need for additional locational signals that the LRIC yields; locational signals already exist between distribution networks, but is the complexity of these also varying within a distribution network a truly desirable characteristic?
·It could become even more difficult to predict charges using the LRIC approach, as the additional locational signals will vary over time. This would mean that suppliers and customers would need to understand how the distribution of network utilisation varies across the region, and then across time periods in order to project future costs. However, the physical data and knowledge is unlikely to be readily available to understand future charging levels. If EHV charges were to become less stable as a result, this could have negative implications on competition.

In summary, we remain unconvinced of the case to move away from the existing charging methodology, particularly when it only relates to part of the network (EHV only) and in only 2 of the 14 distribution networks.

However, if it were to be introduced, we would suggest that the move to the new EHV rates would be completely unacceptable in one step, as it would penalise the customer without their requirements changing and would not allow the customer any time to react to the new arrangements. For instance;

·The highest percentage increase would be a massive 760%, with the largest reduction being 287%.

·The highest £ increase would see costs change by some £737,000/annum, (74% increase on current rates)

If it were to be introduced, then we would definitely favour a phased move to the new charging levels, with cost increases capped at a more reasonable rate, such as 5-10% per annum.

Dow Corning Limited

As a consumer connected to the EHV network, we do not consider ourselves to be experts in the details of the methodology presented and so we will restrict ourselves to general comments.

Based on our understanding of the proposed LRIC method, we believe that it is an appropriate, forward looking, cost reflective methodology which also considers location aspects and previous network reinforcement projects. The methodology reflects the location of Dow Corning's site on the network relative to local generators and also the network reinforcement which was carried out in conjunction with an expansion of our site in the mid 1990's.

Following our comments, we support application of the proposed LRIC methodology for the EHV network.

Norbord Limited

It is difficult to comment on the changes to the WPD Use of System Methodology without understanding the commercial impact on the site itself and there is not sufficient information to accurately achieve this, although on the face of it, the changes do not look attractive in terms of cost reflectivity with respect to HV customers.

Norbord believes that any proposal for a change in methodology should be accompanied by a customer impact assessment and cost benefit analysis.