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WESTERN POWER DISTRIBUTION (SOUTH WEST) PLC
WESTERN POWER DISTRIBUTION (SOUTH WALES) PLC

Modification Proposal

Amendment Proposal: WPD/WALES/WEST/UOS002A

Title: Implementation of the combined Long Run Incremental Cost (LRIC) and Distribution Reinforcement Model (DRM) methodology

Date of Issue: 13/12/2006

FOR APPROVAL BY THE AUTHORITY

This Modification Proposal sets out Western Power Distribution (South West) plc and Western Power Distribution (South Wales) plc ("WPD") proposals to amend WPD's Use of System Charging Methodologies.

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Western Power Distribution

Proposed changes to the Use Of System Methodology

December 2006

1. Summary

1.1 WPD are proposing to use a hybrid Long Run Incremental Cost (LRIC) and Distribution Reinforcement Model (DRM) approach to future use of system pricing - LRIC being applied to EHV networks and the DRM to lower voltage networks.

1.2 Extensive consultation has been undertaken and changes have been made to the approach to reflect concerns that were raised.

1.3 The proposed method better meets the Licence objectives in terms of improved cost reflectivity and transparency with changes made to the original proposal consulted on in July 2006 to improve the stability of the resulting prices.

1.4 The approval of the Authority is sought to implement the revised proposals. If the Authority decides not to veto this proposal before 2nd February 2007 then it will be implemented on 1st April 2007, otherwise it is proposed that implementation will be on the 1st day of the month 5 months after a decision not to veto is made.

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2. Introduction and background

2.1 WPD began work on the development of longer term charging structures in early 2005. Since April 2005 WPD has undertaken a joint structure of charges research project with Bath University which identified different methods for charging for distribution assets. We have undertaken two public consultations and given 5 presentations to the ISG detailing the development of the method.

2.2 This document:

- Summarises and contains the responses to both the consultations published in January 2006 and July 2006
- Details the proposed method and why it better meets the relevant licence objectives
- Includes indicative prices for both WPD licence areas i.e. South West and South Wales, and
- Includes a methodology statement reflecting the proposed methodology and a change marked version of this methodology.
- Seeks the approval of the Authority to implement the revised proposals. If the Authority decides not to veto this proposal before 2nd February 2007 then it will be implemented on 1st April 2007, otherwise it is proposed that implementation will be on the 1st day of the month 5 months after a decision not to veto is made.

Background - Existing arrangements

2.3 Our DUoS charges are based on the 500MW Distribution Reinforcement Model (DRM). The DRM uses an approach outlined by TA Boley and GJ Fowler in 1977 for cost reflective retail tariffs in England and Wales. The details of our current approach are contained in our use of system methodology statement, available from our web site at http://www.westernpower.co.uk under Information for Major Energy Users. The following gives an overall summary.

2.4 This model contains assets at modern equivalent prices (current costs) which are based on a scaled representation of the WPD network. Yardstick costs (£/kW) are calculated from the DRM for each voltage and transformation level.

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

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

2.7 Charges for EHV connected customers contain a site specific element associated with connection assets. At present EHV customer prices do not match the output of the model and these are covered by a transitional arrangement within the methodology.

2.8 An adjustment is made to the yardsticks to reflect the degree that connection contributions have already paid for part of the network.

2.9 Charges for generators are based on an assessment of the likely system costs associated with the connection of generators expressed in terms of £/kW. This is converted to charges at different voltage levels by using yardstick weighting from the 500MW DRM.

2.10 Charges from the above method are then uniformly scaled to achieve the required revenue. The current level of scaling required is around 15%.

3. Consultations undertaken

3.1 Two public consultation have been undertaken during the development of the proposed methodology, one in January 2006 (Appendix 3) and the second in July 2006 (Appendix 5).

3.2 The purpose of the January (Appendix 3) consultation was to:

- Summarise the work that WPD had been doing on reviewing its UoS Methodology
- Seeking views on the type of methodology that is most appropriate to meet our licence obligations
- highlighting key parameters and assumptions in the alternative methods being considered and seeking views on the appropriateness of these assumptions, and
- Seeking views on how the methods should be further developed where known issues had yet to be accommodated

3.3 There were 11 responses

- 3 from EHV connected demand customers
- 5 from Suppliers (all 'large')
- 3 from Distributors (no IDNOs)
- There were no responses from
    - Generators (although all the Suppliers that responded have generation interests)
    - Trade Associations
    - Academics/Consultants
    - Energywatch

3.4 All the responses are attached in appendix 4. The following summarises the responses received.

3.5 A supplier did not agree with Ofgem's view that modelling aligned with forward looking long run incremental costs was a valid basis for a fundamental review of methodology and believes that it has not been demonstrated that there are any issues with the existing approach

3.6 WPD response: the need for a review has been accepted by all Distributors and we believe that both methods outlined in the January consultation are more cost reflective.

3.7 Another supplier believed that the result of consultations by distributors will be difficult to rely on as they are less likely to get responses than those from Ofgem

3.8 WPD response: we agree this is an issue, however we understand that Ofgem would want to be assured that users had been adequately consulted and would undertake their own consultation if necessary

3.9 Concern from a large customer, a supplier and a distributor that WPD are progressing too fast and that we should follow the other distributors. Another supplier was concerned that if distributors implement different solutions then implementation costs would be higher. 2 suppliers were also concerned that billing system changes will be needed

3.10 WPD response: we have spent 14 months on our cost attribution work so far compared to the 3 to 6 months allocated in the COG work plan. Whilst agreeing that there are benefits in a common methodology, methodologies are not a joint licence requirement like the DCode or DCUSC. We do not believe that the methods presented will require changes to billing systems or processes

3.11 2 large customers and a supplier did not agree that the same method need be used for demand and generation, whilst another 2 suppliers believed that consistency was needed to demonstrate non-discrimination/cost reflectivity

3.12 WPD response: we are uncomfortable with demonstrating non-discrimination without a consistent methodology

3.13 2 large customers and 2 suppliers did not believe that they could comment on principles without first seeing the resulting prices

3.14 WPD response: we understand the problem faced by respondents, but felt it was beneficial to consult on principles at an early stage. Further work was required before publishing example prices if they were to be useful.

3.15 However, these same large customers and one of the same suppliers concluded that neither the ICRP or LRIC approach better met the licence objectives generally on the grounds of the methods being complex and dependent on assumptions which would be difficult to validate. This supplier also believes that an allocation of costs is more cost reflective than a model of future investment. Another supplier did believe that both the ICRP and LRIC methods could better meet the objectives at EHV but was concerned about HV and LV networks.

3.16 WPD response: we continue to believe that these methods can better meet our licence objectives, but accept that we will need to justify this further if these methods are to be implemented.

3.17 2 distributors and 2 suppliers highlighted the need for transparency of data/background to assumptions and concern over sensitivity of model to assumptions

3.18 WPD response: The key assumptions in the LRIC model are starting loads, load growth, security factor and reinforcement cost. All forward looking models and business plans have to be based on best estimates of these parameters.

3.19 2 large customers expressed concern that a forward looking model could be cost reflective when 30% of investment is associated with reinforcement

3.20 WPD response: we believe this is part of the revenue reconciliation issue that we accept needs further work. Section 4 details the proposed revenue reconciliation method.

3.21 A large customer was also concerned that forward looking models ignore historic contributions and that as the ICRP/LRIC model only appears to be practical at EHV it should not be used. 2 suppliers and a distributor, however, felt that locational prices have merit but are likely to be impractical at lower voltages

3.22 WPD response: we understand the concern regarding contributions. Unfortunately, an historic contribution has no impact on future investment decisions.

3.23 2 suppliers and a distributor expressed concern that scaling to required revenue would mask cost reflectivity – based on a belief that the model would produce charges representing 10% of required revenue

3.24 WPD response: we agree that reconciliation to required revenue is a significant issue for all methodologies, however dispute that these methodologies will always provide charges covering only a small percentage of required revenue.

3.25 A supplier stated that adoption of a model similar to that used by National Grid would be wrong as the National Grid method has problems

3.26 WPD response: we do not intend commenting on the merits of National Grid's methodology applied to their network

3.27 A supplier and a distributor were concerned that time of day issues were not addressed and that the method did not consider all future cost and the possibility of constraining generation

3.28 WPD response: the method has been further developed to take account of summer loadings and the impact of generation at these times. It now addresses the time of peak usage of each asset in determining the price.

3.29 In summary, the responses to our January consultation indicated that more work was required in the following areas:

- Definition of data being used
- Basis of necessary assumptions
- Lower voltage networks
- Time of use issues
- Reconciliation with allowed revenue
- Presenting the case that a revised method better meets our Licence objectives

3.30 The second consultation in July 2006 (Appendix 5) addressed these issues and had the objective of:

- Summarising responses to our first consultation published in January 2006
- Detailing the proposed method for setting future use of system charges and explaining why it better meets the relevant licence objectives
- Seeking views on the proposed method and the charging assumptions behind it.

3.31 There were 13 responses

- 6 from EHV connected demand customers
- 3 from Suppliers (all 'large')
- 2 from Distributors (no IDNOs)
- 1 from a Trade Association
- 1 from Energywatch
- There were no responses from
  - Generators (although all the Suppliers that responded have generation interests)
  - Academics/Consultants

3.32 All the responses are attached in appendix 6. The following summarises the responses received.

3.33 Treatment of historic contributions - the method described did not take into account historic contributions made for EHV connections. A supplier disagreed with this treatment but did not suggest an alternative.

3.34 WPD response: We accept that a better method for treating contributions is needed. The method now treats all sole use assets as being fully contributed towards in line with current connection charge policy. The only charge associated with these sole use assets is an annuity on their future replacement.

3.35 Views on growth rate assumptions - there were responses from a supplier, 3 large demand customers and 2 distributors. There were views for both higher and lower growth rate assumptions and one for them to vary for each node.

3.36 WPD response: We continue to believe that the use of a global underlying growth rate is appropriate as it is not possible to forecast differential growth rates for any sustained period of time.

3.37 Approach to revenue reconciliation - a supplier agreed with the proposed approach, a supplier was unsure about the use of MEA valuations to split revenues between the two parts of the method and a supplier and a distributor disagreed with the proposed approach.

3.38 WPD response: It is necessary to split the allowed revenue between the LRIC and DRM parts of the model. The work to improve the calculation of security factors has resulted in lower marginal costs and hence a larger reconciliation to required revenue. As a result, a further review of the method of reconciling to required revenue has been undertaken and a revised approach proposed.

3.39 Treatment of NGET Exit Charges as part of revenue reconciliation - a supplier and a distributor both disagreed with this on grounds of cost reflectivity.

3.40 WPD response: Under the 'plugs' methodology, the value of NGET exit charges at a site varies depending on whether the exit point is sole use or shared. NGET Exit Charges only constitute around 2% of the overall charge and we do not believe that separate allocation of these costs would improve cost reflectivity

3.41 Views on whether the draft methodology statement reflects the proposed method - a supplier agreed whilst another disagreed. The supplier that disagreed went on to say that it provided a description at an appropriate level. The concern appeared to be disagreement with the method

3.42 WPD response: Whilst we believe that the method is adequately described, further expansion and explanation has been added.

3.43 Views on whether the method better meets the licence objectives - 2 large demand customers and a trade association agreed that it did, but the trade association qualified this with a need to provide a generation credit where generators defer system reinforcement. A large customer, a supplier, a distributor and one other response did not agree that it better met the objectives. A supplier and a large customer believed it did better meet the objectives in terms of cost reflectivity but not in terms of stability or predictability and a distributor believed that the LRIC method is likely to give too strong a cost signal.

3.44 WPD response: We agree that the method produces cost reflective price signals, but is sensitive to changes in the inputs to the model. To help address potential instability an underlying growth rate will be used throughout the model and a more accurate and consistent method for calculation security factors has been introduced. We believe that these will help to address the concerns expressed in the responses and has resulted in a lower strength marginal cost signal. The concern over the lack of credit to generators that defer winter reinforcement has also been addressed by taking a combination of the winter and summer derived charges. This depends on the contribution that the generator makes to system security. A similar approach has also been introduced for demand prices, where their use of the network in the summer can defer reinforcement caused by generation.

3.45 Transitional arrangements - 3 suppliers, 2 large customers, 1 distributor and 1 other responded all in favour of some transitional arrangements, most but not all concerning price increases. 1 large customer and 1 distributor stated that their price increase would be unacceptable. A large customer stated that negative demand charges would be unfair and a distributor said that consideration should be given to capping negative demand charges at zero.

3.46 WPD response: whilst we understand the concerns about the step changes in prices to EHV customers, we have to balance this against the Licence objective of setting cost reflective prices. In approving the initial methodology, the Authority made clear that exceptional reasons are needed to justify transitional arrangements. As these proposals are intended to be enduring arrangements, we do not believe that exceptional reasons exist to justify transition arrangements. Whilst the method rationally produces some negative demand charges, we understand the concern about the message that these give. As a result, where following reconciliation negative charges remain, it has been decided to cap the scaled marginal part of the EHV demand charges at zero.

3.47 2 suppliers, a trade association prefer a standard solution across all DNOs and the trade association suggested delay to allow comparison with other methods

3.48 WPD response: we understand the merits of a consistent methodology between distributors, however this could only be achieved via regulatory action.

3.49 A trade association response was seeking more locational signals at HV/LV

3.50 WPD response: We do not believe that this is appropriate at this time as methods that give cost reflective locational signals generally need more data and data manipulation than those for average tariffs. We believe that the EHV/HV boundary is an appropriate split point for moving from locational specific charges to average charges.

3.51 2 suppliers, 2 large customers and a distributor expressed concern over the stability of future prices/ability to predict them

3.52 WPD response: further investigation of the use of security factors in the derivation of prices has led us to calculate this in a more sophisticated way which will result in greater consistency between years. As highlighted earlier, an underlying growth rate will be used throughout the model which will also aid stability.

3.53 A supplier and a distributor responded that it is wrong to have a different method at EHV to that used at HV/LV whilst another distributor agreed with the continued use of the DRM at lower voltages

3.54 WPD response: Methods that give cost reflective locational signals generally need more data and data manipulation than those for average tariffs. We believe that the EHV/HV boundary is an appropriate split point for moving from locational specific charges to average charges.

3.55 Energywatch responsed that there is nothing wrong with the DRM approach currently employed.

3.56 WPD response: We agree that the DRM approach continues to be appropriate for lower voltage use of system prices, however for large users of the network that can have a significant influence on it's development it is appropriate to produce cost reflective locational charges and we believe that the LRIC method achieves this.

3.57 Whilst not raised in written responses to our consultations, concerns were also raised over the use of a separate kW and kVAr increments to derive the marginal costs.

3.58 WPD response: We have compared the impact of using separate kW and kVAr increments with the use of a kVA injection at different power factors. The impact on the marginal costs was small, however given these concerns it has been decided to use a kVA increment.

3.59 One area of note concerns large demand customers. The 33 large demand customers connected to WPD's network have 41 sites. In the methodology described in the July consultation, 16 of these sites would see a price increase – some very significant. Of the 6 large demand customers that responded, 5 would see price reductions. 4 of the large demand customer responses were confidential.

3.60 As a result of the consultation responses received and ongoing review of the proposals, changes in the following areas have been made:

- Calculation of security factors - a full contingency analysis is now used which will improve the consistency and stability of calculated prices between years.
- Treatment of off site sole use assets - these are now excluded from the LRIC calculation improving the cost reflectivity of the method. In addition, whilst not referred to by respondents, our DG incentive which sets a target revenue for DG charges excludes contributions and hence it is consistent to exclude these from the LRIC model.
- Treatment of contributions - closer alignment with current connection charges policy has been made improving cost reflectivity.
- Calculation of generator charges - the calculation has been altered to reflect the benefit that generators can make to deferring system reinforcement. A similar approach has been used for demand that defer summer reinforcement by absorbing generation output. These changes improve the cost reflectivity of the method
- Scaling applied to generation charges - these now need to reconcile with the regulatory allowance
- Treatment of negative demand charges - capping of the marginal EHV demand charges at zero proposed.
- Use of separate kW and kVAr increments - this has been changed to the use of a kVA increment at a typical power factor.

4. Proposed Arrangements – LRIC (Long run incremental cost) and DRM

Overall Process

4.1 The proposed arrangements are to calculate charges for the EHV network using a long run incremental cost (LRIC) method and for lower voltages to use a distribution reinforcement method (DRM). These are outlined below.

4.2 The boundary between the two methods is the lower voltage side busbar of the EHV to HV transformation.

4.3 The LRIC method calculates the brought forward (or deferred) reinforcement cost as a result of the addition of an increment of demand or generation at each node. The objective is to link the impact of the behaviour of a user to reinforcement of the assets they utilise.

4.4 An initial load flow is used to determine the time it would take for each asset to reach its capacity assuming underlying utilisation levels and growth rates. Given these timings, and the future reinforcement costs, a net present value of the future reinforcements cost for the network is calculated using a discount rate equal to the cost of capital assessed by Ofgem as part of the price control (currently 6.9%).

4.5 For each node, an increment of demand/generation is added and a new load flow generated. The evaluation of the net present value of the future reinforcement is repeated for the network with this increment present. The difference between the initial and incremental study represents the impact on future reinforcement investment and this is represented as an annual £/kVA at each node by multiplying the difference by an annuity factor. The annuity factor reflects the rate of return on investment and an allowance for operation, repairs and maintenance (the latter is currently 0.9%).

4.6 The above analysis is undertaken for both winter loading conditions and summer loading conditions using the appropriate ratings for the season. A combination of the winter and summer studies is used to determine the prices for demand and generation.

4.7 A full AC load flow is used in the methodology. The increment used is 0.1MVA at 0.95 power factor for demand and at unity power factor for generation. These power factors represent those typical of new connections to the EHV network. The result is not particularly sensitive to the power factor of the injection. The unscaled charges resulted in an increase in calculated revenue of 2.3% if a 0.98 pf were used and a reduction in calculated revenue of 0.9% if a 0.90 pf were used. The assets used to calculate the locational price are those that see a change in flow greater than 1 kVA as a result of the increment.

4.8 The modelling of the impact of generation increments does not include any allowance for fault level or voltage constraints.

Calculations

4.9 If a network component has a capacity of *C*, and supports a power flow of *D*, then the number of years it takes to grow from *D* to *C* for a given load growth rate *r* can be determined from the equation:

$$C = D \times (1 + r)^n$$

where *n* is the number of years *D* takes to reach *C*.

i) Assuming a yearly load growth of r, a starting loading on the asset of D and an asset capacity of C, then the following investment time horizon until reinforcement is determined:

$$n = \frac{\log C - \log D}{\log(1 + r)} \text{ years}$$

ii) If the future investment is the same value as the current circuit, its present value, with a discount rate of d, after n years will be:

$$PV = \frac{Asset}{(1 + d)^n}$$ where *Asset* is the MEA value of the asset

iii) New reinforcement time horizon post injection of demand or generation

$$n_{new} = \frac{\log C - \log D}{\log(1 + r)} \text{ years}$$

iv) Present value with the earlier future reinforcement:

$$PV_{new} = \frac{Asset}{(1 + d)^{n_{new}}}$$

v) Difference in present value:

$$\Delta PV = PVnew - PV$$

vi) Charges are then annuitised:

$$\Delta U = \Delta PV * annuityfactor$$

Detailed Assumptions/Parameters

4.10 In order for the core equations above to be calculated, the LRIC method uses a number of inputs and assumptions;

1. The EHV network is as detailed in the Long Term Development Statement (published in accordance with Licence condition 25). The network used is the existing and committed network that is expected to exist in the December of the year for which charges are to be

calculated. New connections expected to connect during the year for which charges are being calculated will only be included where a connection offer has been accepted and all consents have been obtained. A further set of charges will be calculated using customers' loads/generation for all those with accepted connection offers. The network model will include any changes required to accommodate these loads/generation. This enables potential users to see the charges they would incur if their connection proceeds and allows existing users to see the potential impact on their charges in future years. The additional set of charges will be published separately to our condition 4A charging statement. Where there is expected to be a system overload, for example due to a derogation, the expected system changes to resolve the overload are included in the network model used for charging purposes.

2. The security factor applicable to each asset is assessed by undertaking a full N-1 contingency analysis of the network. The factors are recalculated each time the network is changed or new load estimates used. They are also separately calculated for winter and summer conditions. Assets to be used for this purpose are all WPD owned shared use assets. Where the assets are for the sole use of a connected customer, an annuity representing the future replacement of these assets is used. This is consistent with current connection charge policy of customers contributing to all sole use assets. Customers may also partly contribute to reinforcement of the network as part of their connection charge contribution. This is not taken into account in the method.

3. A modern equivalent asset (MEA) value for each element of the EHV network is used. By analysing historical costs, it has been identified that reinforcement of a transformer costs, in MEA terms, approximately half the cost of the original overloaded transformer. This factor takes into account that the model absorbs existing substation costs into the transformer value and hence the reinforcement has a lower marginal cost. The cost of reinforcing an overloaded 132kV circuit is approximately 1.5 times the MEA value of the overloaded circuit, at 33kV a factor of 2 is applied. The asset lives themselves are not constrained as this is a reinforcement model and not a replacement model and so the time to reinforcement can be greater than the probable asset lives.

4. For the winter peak demands, the model uses the same demands as are used to assess reinforcement. These are detailed in our LTDS. Summer minimum demands are taken as being a percentage of winter peak demands. This percentage is derived for each GSP and applied to the demands supplied by that GSP. These are consistent with the annual data we provide NGET under the Grid Code.

5. The generation export used during the winter period is generally zero unless it is deemed to contribute to security under P2/6. The

generation export used for the summer period is the maximum agreed export capacity. These are the same assumptions that are used for investment planning.

6. The underlying demand and generation growth forecast for the medium term (length of the price control period) is used. It is proposed to use 1% per year for both demand and generation growth. This will be reviewed and set for each price control period.

Calculation of site specific charges

4.11 For individual EHV connected customers, the winter demand used for charging purposes is calculated by weighting together the customers average demands in the time periods ending 17.00, 17.30 and 18.00 during winter weekdays (excluding Christmas and New Year) over the months November to February. The weights used are 38%, 48% and 14% for the half hours ending 17.00, 17.30 and 18.00 respectively and are consistent with those used to derive coincidence factors for lower voltage tariffs. The summer demand used for charging purposes for individual EHV customers is the average of their demand in the time periods ending 06.00 on Sundays in the months of July and August. Where the connection is new or significant changes have been made to the agreed capacity a best estimate will be used for the winter charging demand and summer charging demand taking into account the typical ratio seen of agreed supply capacities to charging demands for existing customers.

4.12 For connections to other Licence Distributors, the demand used is that agreed between WPD and the distributor. We would expect this to be the level of capacity necessary to allow them to achieve compliance with their security standard.

4.13 For EHV demand sites and Licensed Distributors, the charge is calculated as follows:

- For each branch used by the demand determine whether reinforcement is driven first by winter or summer conditions.
- Where winter, the branch price is the winter price multiplied by the assessed demand at the time of peak (as defined in paras 4.11 and 4.12)
- Where summer, the branch price is the negative of the summer price multiplied by the assessed summer demand (as defined in paras 4.11 and 4.12)
- The demand price is the sum of the branch prices plus the annuitised cost of the future replacement value of the sole use assets associated with the connection point and the allocation of network rates

4.14 For EHV generation sites, the charge is calculated as follows:

- For each branch used by the generation determine whether reinforcement is driven first by winter or summer conditions.

- Where summer, the branch price is the summer price multiplied by the agreed export capacity
- Where winter, the branch price is the negative of the winter price multiplied by the P2/6 contribution to security.
- The generator price is the sum of the branch prices plus the annuitised cost of the future replacement value of the sole use assets associated with the connection point

Lower voltage networks

4.15 Application of the LRIC methodology was tested on three HV networks. These were urban, mixed urban and rural in nature. Only the heavily loaded urban HV network gave locational prices representing more than a few percent of the required revenue. Hence, using an LRIC method at these voltage levels would result in most of the price being represented by the reconciliation to allowed revenue. In addition, the volume of data and data manipulation grows rapidly on lower voltage networks making the application of LRIC impractical at these voltages for anything other than representative networks. As a result we have decided to continue to use the distribution reinforcement model (DRM) methodology at voltage levels below the lower voltage busbar at EHV to HV substations.

HV and LV generator charges

4.16 Following the decision not to veto modification proposal WPD/WALES/WEST/UOS001 (Removal of GDUoS charges for generation associated with connections supplied under profiles 1 to 4), there are no proposed changes to the methodology for the calculation of generator charges at HV and LV.

Revenue Reconciliation

4.17 Using a hybrid of LRIC and DRM for demand charges requires the allowed revenue to be split between the EHV and lower voltage networks.

4.18 It is proposed that for demand charges, the split of required revenue between the EHV network and lower voltage networks is set in proportion to the modern equivalent asset (MEA) valuation of each network. This approach results in a different split of allowed revenue between these networks than that currently derived from the existing DRM approach. This is shown below:

	S West		S Wales	
	Current method	LRIC/DRM	Current Method	LRIC/DRM
EHV	47%	39%	48%	42%
Lower voltage	53%	61%	52%	58%

Comparison of the revenue split between EHV and lower voltage networks for the existing and proposed methodologies.

4.19 Two approaches were considered for reconciling the LRIC method to the required revenue. These were:

- Adjustment of the derived charges by a uniform £/kVA adjustment or
- Adjustment by a uniform percentage

4.20 The choice of reconciliation method is influenced by the degree of reconciliation needed. In general adjustment by a uniform £/kVA will result in the least distortion to the marginal charges where significant reconciliation is needed. A large demand customer could be connected to part of the network with significant spare capacity and hence have a very low marginal charge. In this case, adjustment by a uniform percentage would result in the large customer receiving a very low charge per kVA compared to a customer connected to the HV network despite both receiving the general benefits of connection to a distribution network that are not related to marginal load changes. Use of a uniform £/kVA adjustment is also likely to adjust negative marginal EHV charges into positive charges and hence minimise the number of scaled marginal charges that need to be capped at zero.

4.21 We operate under a generation incentive scheme for generators that connected after 1st April 2005. This incentive scheme can result in an allowed income that is positive whilst the proposed methodology may produce negative charges for some generators. Setting charges each year to achieve the required revenue under the incentive scheme could result in very large changes in generator charges from year to year due to the small number of generators covered by the incentive arrangements. As a result, we are proposing to continue with a 10% cap on changes in a 12 month period once a generators change is set. This will result in a small degree of cross subsidy between generators and demand customers.

4.22 We believe that for demand charges adjustment to required revenue by a uniform £/kVA results in the least distortion to the marginal charges. Due to the particular issue of the generation incentive scheme in relation to the charges that could result from the methodology, adjustment of the generation charges by a uniform £/kVA adjustment will also be needed.

4.23 Hence, the following approach is proposed:

For demand charges:

- Excluding rates and NGET exit charges the required revenue is split between the EHV network and lower voltage networks using a modern equivalent asset (MEA) valuation.
- Asset quantities used for this evaluation are consistent with those contained in our Regulatory Reporting Tables together with MEA assets values used for our long term investment planning
- NGET exit charges are recovered with the reconciliation of the LRIC part of the model
- At the EHV level reconciliation will be made by a £/kVA adder using the winter total kVA
- Averaged £/kVA from the EHV model at the 33/11kV level will be used to populate the top levels of the DRM
- Reconciliation of the DRM to required revenue will be achieved by uniform percentage scaling, excluding the parts derived from the LRIC model

For generation charges:

- Once set, EHV generator charges will be capped to a change no greater than 10% in any 12 month period
- For new EHV generators, a £/kVA adjustment will be applied to all generators with accepted connection offers for the year charges are being set in order to meet allowed revenue excluding over/under recoveries from previous years under the generator incentive
- Due to the continuing low level of generation connections to the HV and LV networks and hence the potential for volatile charges, the 10% price movement per annum cap in the existing methodology will be retained for HV and LV generator charges
- For the avoidance of doubt, the capping arrangements to generator charges will only apply until 31st March 2010. This may need to be reviewed following Ofgem deciding on the treatment of use of system charges to generators with connection agreements prior to April 2005.
- Due to the difficulties in reconciling generator charges to the incentive arrangements, it is also proposed to remove the ability for generators connected pre April 2005 to opt into the arrangements for post April 2005 generator connections

4.24 Both the LRIC and DRM parts of the model recover forecast network rates in proportion to the revenue recovered.

4.25 Where after the revenue reconciliation process the resulting EHV demand charge is negative, it is proposed that the scaled marginal £/kVA charge applicable to that demand site will be set to zero and the overall reconciliation to required revenue adjusted accordingly.

4.26 Currently NGET exit charges are allocated via yardsticks in the DRM and represent around 2% of required revenue. Under the 'plugs' methodology, the value of NGET exit charges at a site varies depending on whether the exit point is sole use or shared. It is therefore proposed that exit charges are recovered via the revenue reconciliation process described above.

Testing of model undertaken/example of impact of a new connection on existing connections

4.27 The following testing and processes to detect errors have been undertaken:

- Comparison of results from the models run for different years
- Confirmation that the network is compliant with the security standard
- Sample check on movement between runs for specific cases
- Comparison of results for differing power factor injections
- Comparison of results with MVA injection rather than separate MW and MVAr injections.
- During the process a number of checks are made to ensure data handling errors are not made including checking for duplicate data and checking no data is lost.
- Examination of the impact of the size of the incremental injection.

4.28 Attachment 1 shows the impact of the addition of a generator to an existing network. This is a real example of a potential change as the generator concerned has accepted a connection offer. It is not included in the indicative prices for 07/08 as all the necessary permissions have not yet been obtained.

Tariff structures

4.29 The process described above is about recovering a cost reflective share of the required revenue. Demand charges for EHV customers will continue to be shown as a fixed charge and a £/kVA per day charge. For EHV customers with power factors worse than 0.95 we will show the reduction in charge that would result from operating at an improved power factor.

4.30 The changes resulting from this revised methodology will not require any changes to billing systems or processes outside of WPD.

Changes to Methodology Statement

4.31 The above proposals require a considerable revision to our methodology statements. The proposed changes are shown in the attached methodology statements. Change marked versions are also attached.

5. Proposals versus licence obligations

Licence Obligations

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

- facilitate the discharge of the DNO's obligations under the Act and its licence; and

- facilitate competition in supply and generation, and not restrict competition in transmission or distribution; and

- be cost reflective, as far as is practicable once implementation costs are taken into account and

- take into account developments in the licensee's distribution business.

5.2 OFGEM in its Structure of Charges documents and in particular in the May 2005 Consultation paper has indicated the importance of deriving a charging model which delivers economic efficiency. Economic efficiency as defined by OFGEM means "that consideration should be given to ensuring lowest cost provision of the system which would include the requirement for the provision of efficient investment signals to customers such that future network needs are met efficiently."

5.3 The Ofgem May 2005 Structure of Charges paper also identified the following high level charging principles:

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

5.4 The LRIC method allows locational prices to be determined taking into account both the extent that assets are used to supply a node on the network and also the spare capacity that exists in those assets. This compares with the existing DRM method that uses average £/kW per voltage level. Hence the LRIC method is more cost reflective than the DRM. The locational signals derived for the HV and LV networks were only a small percentage of the required revenue (see section 4) and hence we do not believe that application of the LRIC method at these voltages would be more cost reflective than the existing DRM method. In addition, it is impractical to model the entire HV and LV networks and hence 'average' models would need to be used which would remove the main benefit of a locational cost signal.

5.5 The LRIC method is simple in concept; however, the volume of data used gives the appearance of a complex method. As detailed in section 4, there is no intention to change tariff structures as part of the application of LRIC to EHV networks and hence the application of Use of System charges will remain easy to understand and apply.

5.6 This paper and the proposed methodology statement set out the formulae and assumptions used. This is a greater level of transparency of EHV charges than has been available under the DRM approach. Our intention is to make available details of the model used each year.

5.7 LRIC prices will vary due to changes in users' demands on the network, the networks configuration and the projection of future load growth used. Our current knowledge of changes in demands on the EHV network and its configuration are published annually in our LTDS and hence give users the same level of information as is available to us in predicting future changes in prices. The method is sensitive to changes in the forecast growth in demand and generation and hence it is intended to use medium term growth forecasts underlying the price control and only vary these during a price control where strong evidence of a significant variation emerges.

5.8 Given the method's improved cost reflectivity and transparency, we believe that it will better facilitate competition in the supply and generation of electricity and will not restrict competition in transmission or distribution. We also believe that the improved cost reflectivity at the EHV level will reduce perverse incentives to connect to the distribution or transmission network due to the use of averaged charges on the distribution network.

6. Impact of proposed arrangements on prices

6.1 The following tables show the results from the revised methodology. They compare existing 2006/07 prices with 2007/08 prices on the existing methodology (both with and without RPI capping of EHV charges) and 2007/08 charges produced from the proposed LRIC/DRM methodology. For completeness, a comparison of the 2007/08 charges for EHV connected demand customers with a uniform percentage scaling applied is also shown.

6.2 In addition, graphs are included that show the winter LRIC prices for all EHV nodes with load or generation present. These prices are the derived marginal prices including the scaling applied to these prices. The graphs also show within which price ranges EHV demand customers are connected and also show existing methodology derived prices for these customers. Finally, graphs are included showing the difference in the spread of LRIC prices that would result if a uniform percentage scaling rather than a £/kVA adder were used in the LRIC methodology.

6.3 Tables are also included that show the unscaled generator prices for the existing generators connected to our EHV networks. There are 2 generators that have connected since April 2005 and 1 other expected to connect during 2007/08 in the South West. In Wales there are currently no EHV generators subject to use of system charges. There are 10 generators in Wales seeking connection in 2007/08, however only three of these comply with the test detailed in 4.10. Tables are included showing the charges for these generators and the result of the price capping applicable. Tables are also included showing the prices that would apply to the other generators seeking connection in 2007/08 should they proceed and, in addition, tables showing how these connections would affect other users' prices in subsequent years.

South West - Comparison of current prices with forecast 07/08 prices under the existing methodology and under the proposed methodology

Profile	Tariff		2006/07 Actual Price p/kWh	2007/08 DRM Scaled Price p/kWh	2007/08 LRIC_DRM approach p/kWh	% disturbance LRIC_DRM vs DRM
profile 1	domestic unrestricted		1.92	2.16	2.10	-3%
profile 2	economy 7	day	2.23	2.50	2.40	-4%
profile 2	economy 7	night	0.43	0.47	0.54	14%
profile 3	non domestic unrestricted		1.55	1.72	1.74	1%
profile 4	non domestic economy 7	day	2.14	2.37	2.42	2%
profile 4	non domestic economy 7	night	0.41	0.37	0.42	14%
profile 5to8	low voltage supplies with substation		1.32	1.48	1.52	3%
profile 5to8	low voltage supplies		1.63	1.84	1.99	8%
HHM	High voltage supplies		0.70	0.81	0.81	0%
HHM	low voltage supplies with substation		1.06	1.18	1.20	2%
HHM	low voltage supplies		1.31	1.47	1.54	5%
UMS	NHHM		1.78	1.95	2.16	10%
UMS	HHM		1.70	1.90	2.11	11%

South West - comparison of existing EHV demand customer prices with forecast 07/08 prices under the existing methodology and the proposed methodology (also showing the impact of the current RPI capping of EHV prices in the current methodology)

EHV Designated Sites Load Sites	2006/07 Actual Price £s	2007/08 RPI capped prior year £s	2007/08 DRM Scaled Price £s	2007/08 LRIC_DRM approach £s	% disturbance LRIC_DRM vs DRM
SWW Tamar	30,061	31,113	21,088	5,690	-73%
SWW Roadford	42,704	44,198	30,118	22,419	-26%
ROF Puriton	50,985	52,770	35,880	21,851	-39%
Caberboard	180,702	187,026	128,074	135,115	5%
St Regis, Watchet	322,765	334,062	227,949	118,796	-48%
Tarmac, Stancombe Quarry	37,064	38,361	26,000	19,838	-24%
IMERYS	995,603	1,030,449	1,030,662	918,350	-11%
British Aerospace	201,057	208,094	344,541	208,688	-39%
Terra Nitrogen	607,984	629,264	407,640	410,716	1%
Rolls Royce TT	51,210	53,002	298,597	157,412	-47%
Rolls Royce Gen	76,263	78,932	9	45,674	501965%
Devonport	536,900	555,692	431,183	679,635	58%

South West - comparison of resulting prices under the proposed methodology with different methods of reconciliation to required revenue

Comparison of Different Revenue Reconciliation Approaches			2007/08 LRIC_DRM Unused Recovery - Percentage Scaling approach p/kWh	2007/08 LRIC_DRM Unused Recovery - £/kVA approach p/kWh
profile 1	domestic unrestricted		2.10	2.10
profile 2	economy 7	day	2.41	2.40
profile 2	economy 7	night	0.54	0.54
profile 3	non domestic unrestricted		1.75	1.74
profile 4	non domestic economy 7	day	2.43	2.42
profile 4	non domestic economy 7	night	0.42	0.42
profile 5to8	low voltage supplies with substation		1.53	1.52
profile 5to8	low voltage supplies		1.99	1.99
HHM	High voltage supplies		0.82	0.81
HHM	low voltage supplies with substation		1.21	1.20
HHM	low voltage supplies		1.55	1.54
UMS	NHHM		2.17	2.16
UMS	HHM		2.12	2.11
			£s	£s
SWW Tamar			5,080	5,690
SWW Roadford			11,613	22,419
ROF Puriton			-1,970	21,851
Caberboard			10,783	135,115
St Regis, Watchet			-16,317	118,796
Tarmac, Stancombe Quarry			26,017	19,838
IMERYS			814,792	918,350
British Aerospace			38,431	208,688
Terra Nitrogen			77,637	410,716
Rolls Royce TT			31,119	157,412
Rolls Royce Gen			44,707	45,674
Devonport			617,275	679,635
Total EHV sites recovery			1,659,166	2,744,183

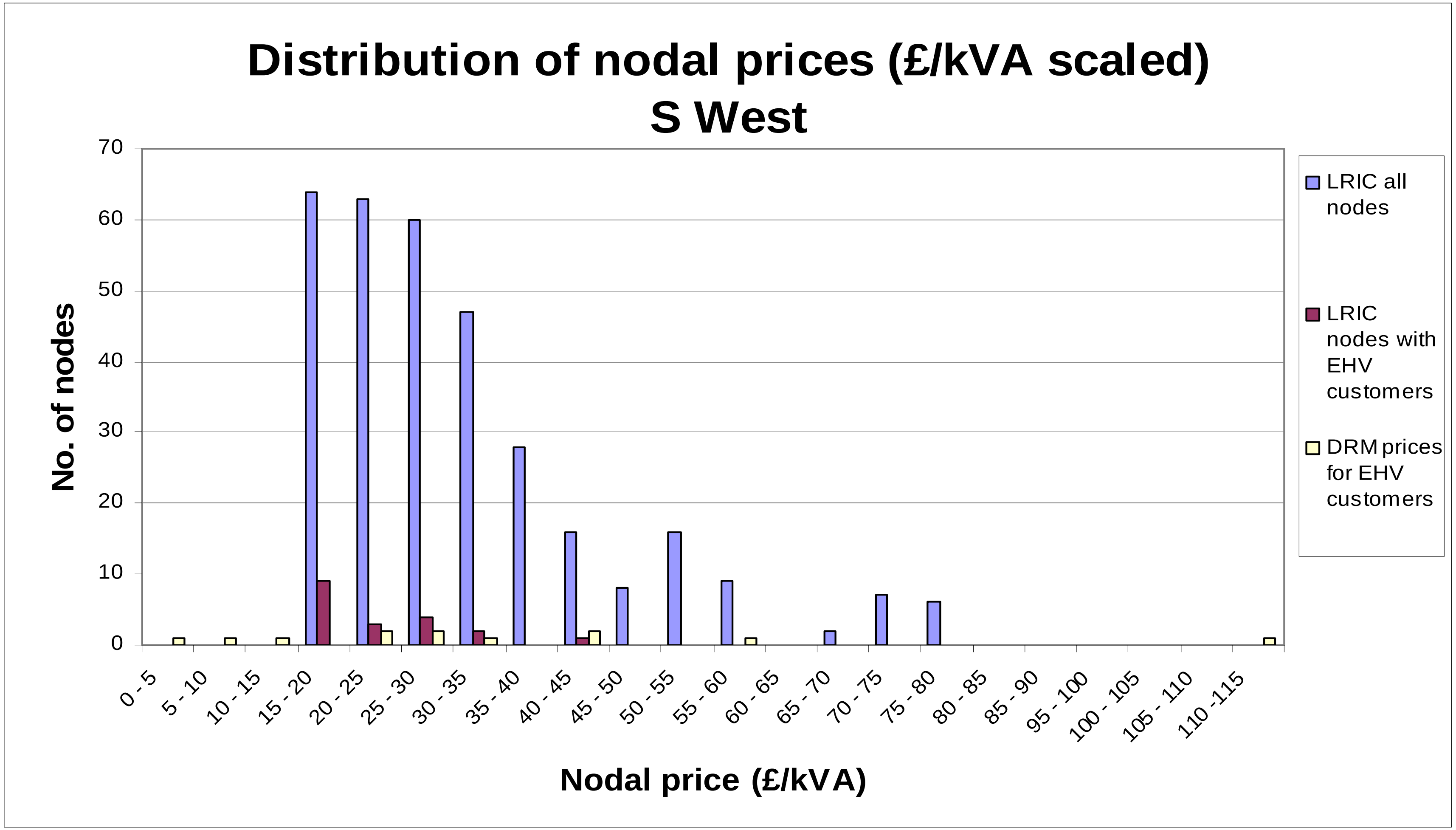
South West - Generation charges - Illustrative charges for 2007/08 (note only 3 of these generators connected after April 2005 and hence will be subject to charges - their reconciled charges are shown below the table)

EHV Designated Sites **Generation Sites - for info only**	Illustrative Charge Only 2007/08 (£s)
CHELSON GENERATOR 33kV	-22,723
BRITISH CELLOPHANE 6.6kV	7,028
St BREOCK 33kV	14,637
CARLAND CROSS 33kV	989
COLD NORTHCOTT 33kV	3,713
FOUR BURROWS 33kV	3,100
ISLES OF SCILLY 11kV	-137,656
LYNTON 11kV	3,155
BRADON FARM 33kV	21,524
HUNTWORTH GENERATOR 33kV	20,785
BEARS DOWN WINDFARM 33kV	4,614
ST DAY LANDFILL 33kV (United Mines)	-6,154
MARSH BARTON 132kV POWER STN	-116,369
ROLLS ROYCE FILTON 132kV	38,035
CONNON BRIDGE LANDFILL 33kV	5,738
FORESTMOOR WINDFARM	2,113
DARRACOTT WINDFARM	2,140

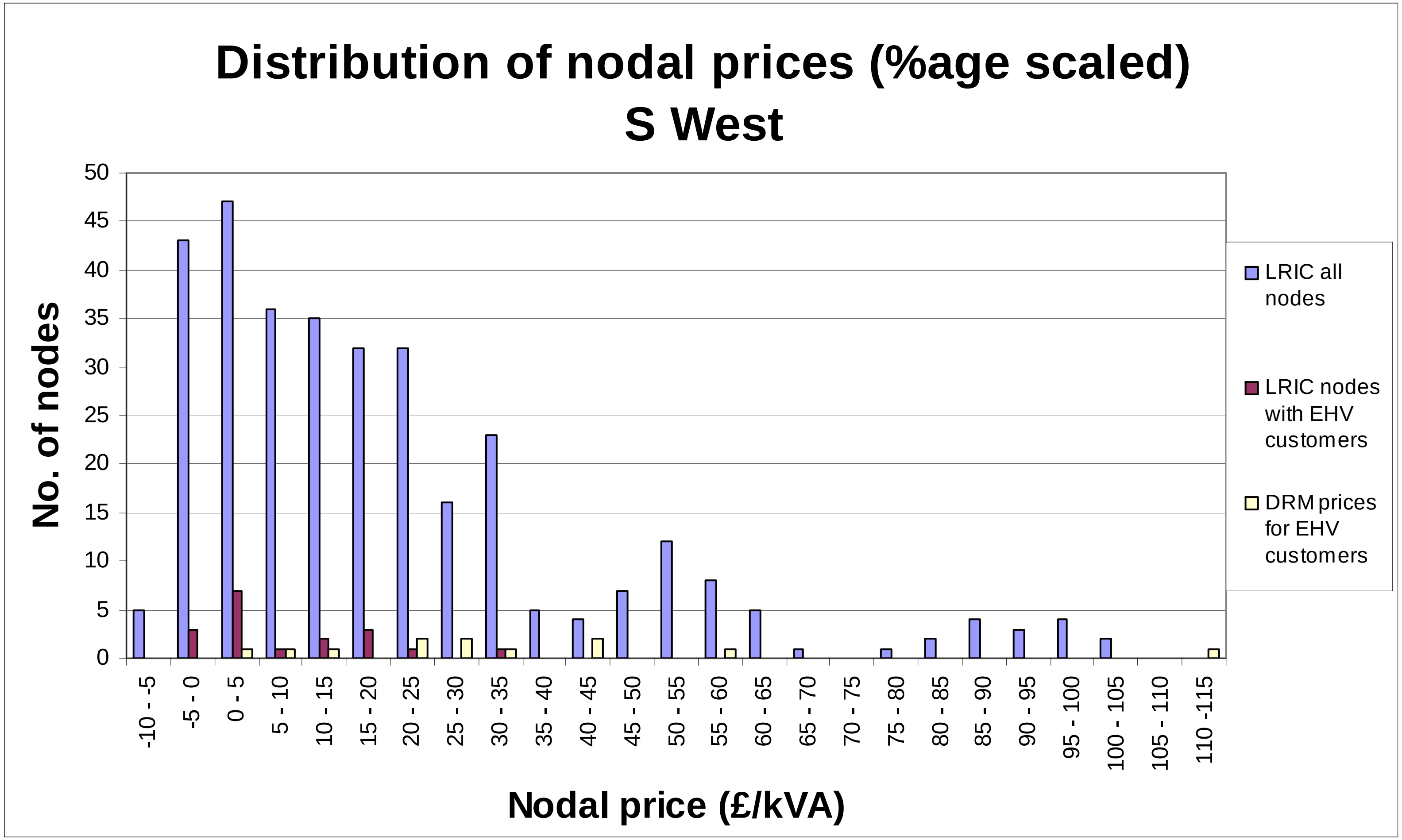
Allowed Income Allocation 2007/08

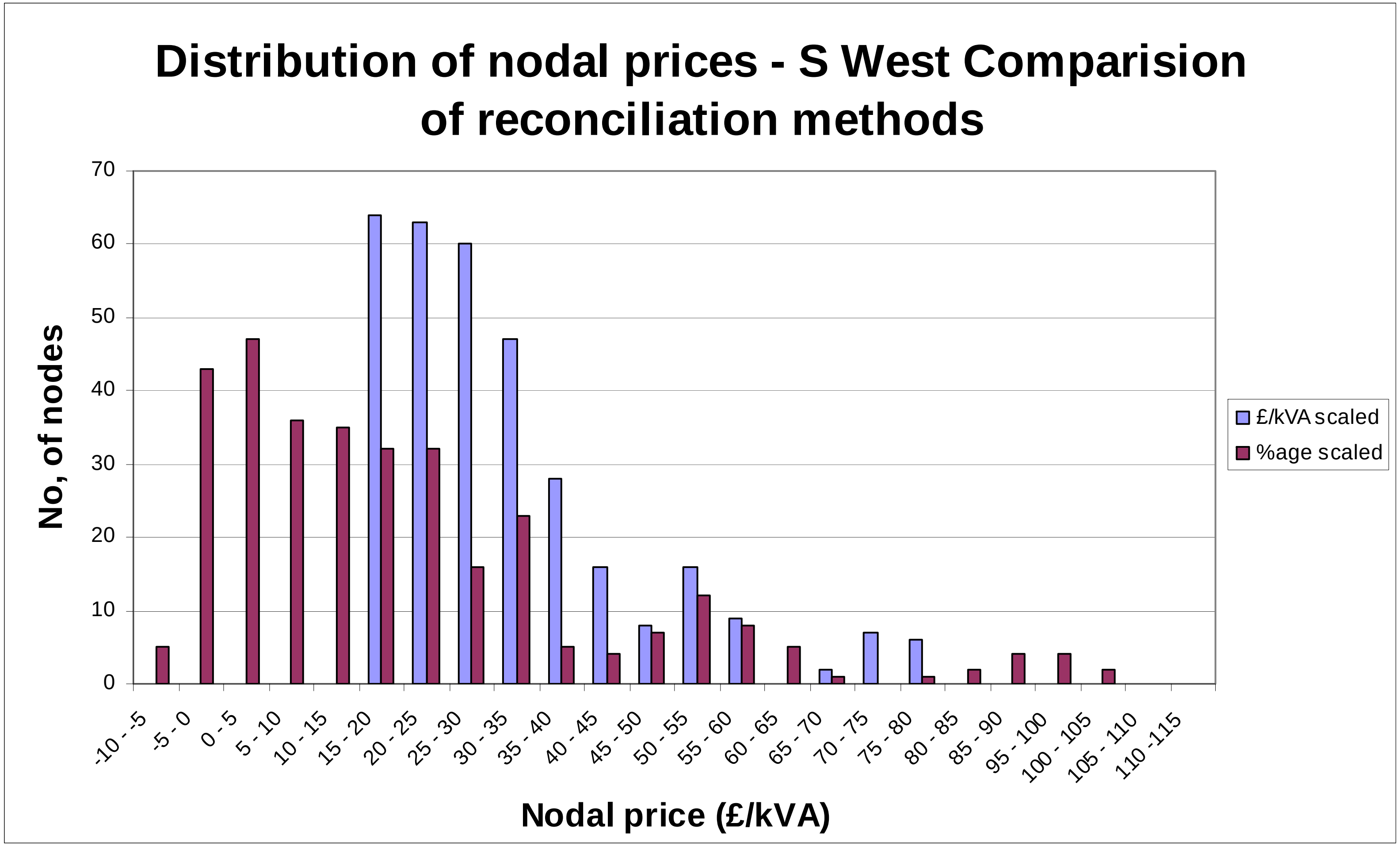
Connon Bridge	1.46	MVA
Chelson Meadow	1.05	MVA
Darracott	2.67	MVA
allowed income £ per kW	2.65	
Total allowed income	£13,755.81	
kVA scaling factor	£4,054.11	

	2007/08 pre scaling charge	2007/08 scaling	2007/08 Final Charge	2006/07 current charge	2007/08 capped charge
CONNON BRIDGE LANDFILL 33kV	£1,966.69	£5,919.00	£7,885.70	£9,006.01	£8,105.41
CHELSON GENERATOR 33kV	-£11,361.45	£4,256.82	-£7,104.63	£6,476.93	£5,829.23
DARRACOTT	£2,139.94	£10,834.80	£12,974.74		
	-£7,254.81	£21,010.62	£13,755.81	£15,482.94	£13,934.64



Distribution of nodal prices (£/kVA scaled)
S West
No. of nodes
0
10
20
30
40
50
60
70
0 - 5
5 - 10
10 - 15
15 - 20
20 - 25
25 - 30
30 - 35
35 - 40
40 - 45
45 - 50
50 - 55
55 - 60
60 - 65
65 - 70
70 - 75
75 - 80
80 - 85
85 - 90
95 - 100
100 - 105
105 - 110
110 -115
Nodal price (£/kVA)
LRIC all nodes
LRIC nodes with EHV customers
DRM prices for EHV customers


Distribution of nodal prices (%age scaled)
S West
No. of nodes
50
45
40
35
30
25
20
15
10
5
0
-10 - -5
-5 - 0
0 - 5
5 - 10
10 - 15
15 - 20
20 - 25
25 - 30
30 - 35
35 - 40
40 - 45
45 - 50
50 - 55
55 - 60
60 - 65
65 - 70
70 - 75
75 - 80
80 - 85
85 - 90
90 - 95
95 - 100
100 - 105
105 - 110
110 -115
Nodal price (£/kVA)
LRIC all nodes
LRIC nodes with EHV customers
DRM prices for EHV customers


Distribution of nodal prices - S West Comparision of reconciliation methods
No, of nodes
0
10
20
30
40
50
60
70
-10 - -5
-5 - 0
0 - 5
5 - 10
10 - 15
15 - 20
20 - 25
25 - 30
30 - 35
35 - 40
40 - 45
45 - 50
50 - 55
55 - 60
60 - 65
65 - 70
70 - 75
75 - 80
80 - 85
85 - 90
95 - 100
100 - 105
105 - 110
110 -115
Nodal price (£/kVA)
£/kVA scaled
%age scaled

South Wales - Comparison of current prices with forecast 07/08 prices under the existing methodology and under the proposed methodology – committed generation only included

Profile	Tariff		2006/07 Actual Price p/kWh	2007/08 DRM Scaled Price p/kWh	2007/08 LRIC_DRM approach p/kWh	% disturbance LRIC_DRM vs DRM
profile 1	domestic unrestricted		2.24	2.28	2.17	-5%
profile 2	economy 7	day	2.59	2.63	2.50	-5%
profile 2	economy 7	night	0.30	0.30	0.38	26%
profile 3	non domestic unrestricted		1.73	1.76	1.82	3%
profile 4	non domestic economy 7	day	2.24	2.29	2.34	2%
profile 4	non domestic economy 7	night	0.35	0.35	0.44	26%
profile 5to8	low voltage supplies		1.59	1.73	2.04	18%
HHM	High voltage supplies		0.81	0.85	0.82	-3%
	low voltage supplies		1.43	1.48	1.61	9%
UMS	NHHM		1.84	1.98	2.23	13%
	HHM		1.86	1.92	2.14	11%

South Wales - comparison of existing EHV demand customer prices with forecast 07/08 prices under the existing methodology and the proposed methodology (also showing the impact of the current RPI capping of EHV prices in the current methodology) – committed generation only

EHV Designated Sites Load Sites	2006/07 Actual Price £s	2007/08 RPI capped prior year £s	2007/08 DRM Scaled Price £s	2007/08 Indicative LRIC_DRM £s	% change
AES	73,522	76,095	13,441	32,515	142%
Alcoa	380,447	393,762	345,288	318,366	-8%
Alpha Steel	219,548	227,232	92,029	283,145	208%
ASW 33/11	189,008	195,623	31,229	212,958	582%
ASW Rod Mill	152,665	158,008	424,842	371,458	-13%
Blagden	112,088	116,011	226,319	98,269	-57%
Blue Circle Cement	186,190	192,707	124,203	47,882	-61%
Boc Margam	517,139	535,239	998,936	677,082	-32%
BP Llandarcy	39,497	40,879	35,838	34,388	-4%
British Alcan	264,112	273,356	333,161	274,852	-18%
Corus Margam	1,090,401	1,128,565	666,004	749,240	12%
Corus Orb	321,357	332,604	393,391	212,994	-46%
Corus Trostre	445,592	461,188	492,925	466,195	-5%
DCWW Nantgaredig	60,827	62,956	7,203	8,291	15%
DCWW Rover Way	79,902	82,699	186,170	230,719	24%
Dow Corning	58,028	60,059	34,079	425	-102%
Elf Oil	543,032	562,039	556,395	925,326	66%
Ford Bridgend	199,673	206,662	366,118	297,151	-19%
Ford Swansea	194,370	201,173	192,946	127,511	-34%
Fort James	127,119	131,568	208,942	97,736	-53%
Inco (Europe)	176,193	182,360	37,017	111,567	201%
Mainline Pipelines	83,549	86,473	43,272	52,701	22%
Monsanto	94,769	98,086	128,930	119,080	-8%
PCC Texaco	836,033	865,294	719,071	944,263	31%
Petroplus	20,863	21,594	38,521	46,455	21%
Simms	138,379	143,222	15,129	16,103	6%
Swansea University	63,298	65,514	90,705	68,179	-25%
Tower	82,474	85,360	41,367	50,957	23%
Whitbread Magor	77,117	79,816	58,225	85,518	47%
Dragon				477,910	
South Hook				671,637	
Cardiff Sports Village				359,330	
Aberystwyth - Manweb	1,020,000			778,672	

South Wales - comparison of resulting prices under the proposed methodology with different methods of reconciliation to required revenue – committed generation only

Profile	Tariff		2007/08 Indicative LRIC_DRM unused recovery - percentage scaling approach p/kWh	2007/08 Indicative LRIC_DRM unused recovery - £/kVA approach p/kWh
profile 1	domestic unrestricted		2.21	2.17
profile 2	economy 7	day	2.55	2.50
profile 2	economy 7	night	0.38	0.38
profile 3	non domestic unrestricted		1.85	1.82
profile 4	non domestic economy 7	day	2.38	2.34
profile 4	non domestic economy 7	night	0.44	0.44
profile 5to8	low voltage supplies		2.08	2.04
HHM	High voltage supplies		0.85	0.82
HHM	low voltage supplies		1.64	1.61
UMS	NHHM		2.27	2.23
UMS	HHM		2.18	2.14
			£s	£s
AES			-61,881	32,515
Alcoa			193,252	318,366
Alpha Steel			7,825	283,145
ASW 33/11			145,013	212,958
ASW Rod Mill			384,549	371,458

Blagden	6,898	98,269
Blue Circle Cement	-24,238	47,882
Boc Margam	27,476	677,082
BP Llandarcy	25,420	34,388
British Alcan	184,698	274,852
Corus Margam	316,918	749,240
Corus Orb	19,888	212,994
Corus Trostre	249,024	466,195
DCWW Nantgaredig	9,327	8,291
DCWW Rover Way	158,251	230,719
Dow Corning	-35,519	425
Elf Oil	1,199,201	925,326
Ford Bridgend	156,267	297,151
Ford Swansea	76,947	127,511
Fort James	19,983	97,736
Inco (Europe)	57,399	111,567
Mainline Pipelines	61,368	52,701
Monsanto	103,822	119,080
PCC Texaco	275,539	944,263
Petroplus	55,580	46,455
Simms	6,739	16,103
Swansea University	50,442	68,179
Tower	32,986	50,957
Whitbread Magor	63,413	85,518
Dragon	584,332	477,910
South Hook	798,463	671,637
Cardiff Sports Village	407,531	359,330
Aberystwyth - Manweb	170,833	778,672
Total EHV sites recovery	5,727,749	9,247,708

South Wales - Generation charges - Illustrative charges for 2007/08

EHV Designated Sites Generation Sites - for info only	Illustrative Charge Only 2007/08 (£s)
ABERAMAN PARK 33kV	-39,416
BLAEN BOWI 33KV GEN	3,201
BLAEN CREGAN 66KV	189,017
BRITISH ENERGY 33kV	322
BRYN TITLI W/FARM 66KV GEN	8,513
CORNELLY 33kV	3,872
CRYMLYN BURROWS 33KV	-13,904
DYFFRYN BRODYN 33 KV GEN	13,810
LLANDOVERY 33kV	45,650
PARC CYNOG 33KV	21,774
PWLLFA GWATKIN 33 kV	-6,927
SULLY 132kV	1,742,282
TAFF ELY WINDFARM 33KV GEN	3,652
	1,923,525

Post April 2005 Connections

Allowed income allocation 2007/08			
Trecatti		5.1	MVA
BOC Biomass		13	MVA
Blaen Bowi additional		3.9	MVA
Total additional Capacity		22	MVA
allowed income £ per kW	2.65		
Total allowed income	£58,393.67		
kVA scaling factor	£4,786.19		

Scaling to required revenue	pre scaling charge	scaling	2007/08 Final Charge	2006/07 current charge
Trecatti	-£54,583	£24,410	- £30,174	0
BOC Biomass	£6,262	£62,221	£68,483	0
Blaen Bowi additional	£1,419	£18,666	£20,085	0
	-£46,903	£105,296	£58,394	£0

South Wales Comparison of illustrative charges for 2007/08 with committed generation connected and with all generators with signed connection applications connected.

Profile	Tariff		2007/08 LRIC_DRM approach p/kWh Committted Generation	2007/08 LRIC_DRM approach p/kWh Generators with Signed Connection Applications	Difference
profile 1	domestic unrestricted		2.17	2.17	-0.1%
profile 2	economy 7	day	2.50	2.50	-0.1%
profile 2	economy 7	night	0.38	0.38	0.0%
profile 3	non domestic unrestricted		1.82	1.81	-0.1%
profile 4	non domestic economy 7	day	2.34	2.33	-0.1%
profile 4	non domestic economy 7	night	0.44	0.44	0.0%
profile 5to8	low voltage supplies		2.04	2.04	-0.1%
HHM	High voltage supplies		0.82	0.82	-0.1%
	low voltage supplies		1.61	1.61	-0.1%
UMS	NHHM		2.23	2.23	-0.1%
	HHM		2.14	2.14	-0.1%

South Wales EHV Sites Comparison of illustrative charges for 2007/08 with committed generation connected and with all generators with signed connection applications connected.

	2007/08 Indicative LRIC_DRM approach Committed Generation £s	2007/08 Indicative LRIC_DRM approach Generators with Signed Connection Applications £s	Difference
AES	32,515	32,438	-0.2%
Alcoa	318,366	338,790	6.4%
Alpha Steel	283,145	283,116	0.0%
ASW 33/11	212,958	213,978	0.5%
ASW Rod Mill	371,458	371,866	0.1%
Blagden	98,269	97,965	-0.3%
Blue Circle Cement	47,882	48,288	0.8%
Boc Margam	677,082	677,014	0.0%
BP Llandarcy	34,388	34,411	0.1%
British Alcan	274,852	274,835	0.0%
Corus Margam	749,240	928,192	23.9%
Corus Orb	212,994	212,973	0.0%
Corus Trostre	466,195	466,159	0.0%
DCWW Nantgaredig	8,291	6,446	-22.3%
DCWW Rover Way	230,719	231,351	0.3%
Dow Corning	425	425	0.0%
Elf Oil	925,326	925,298	0.0%
Ford Bridgend	297,151	297,129	0.0%
Ford Swansea	127,511	89,258	-30.0%

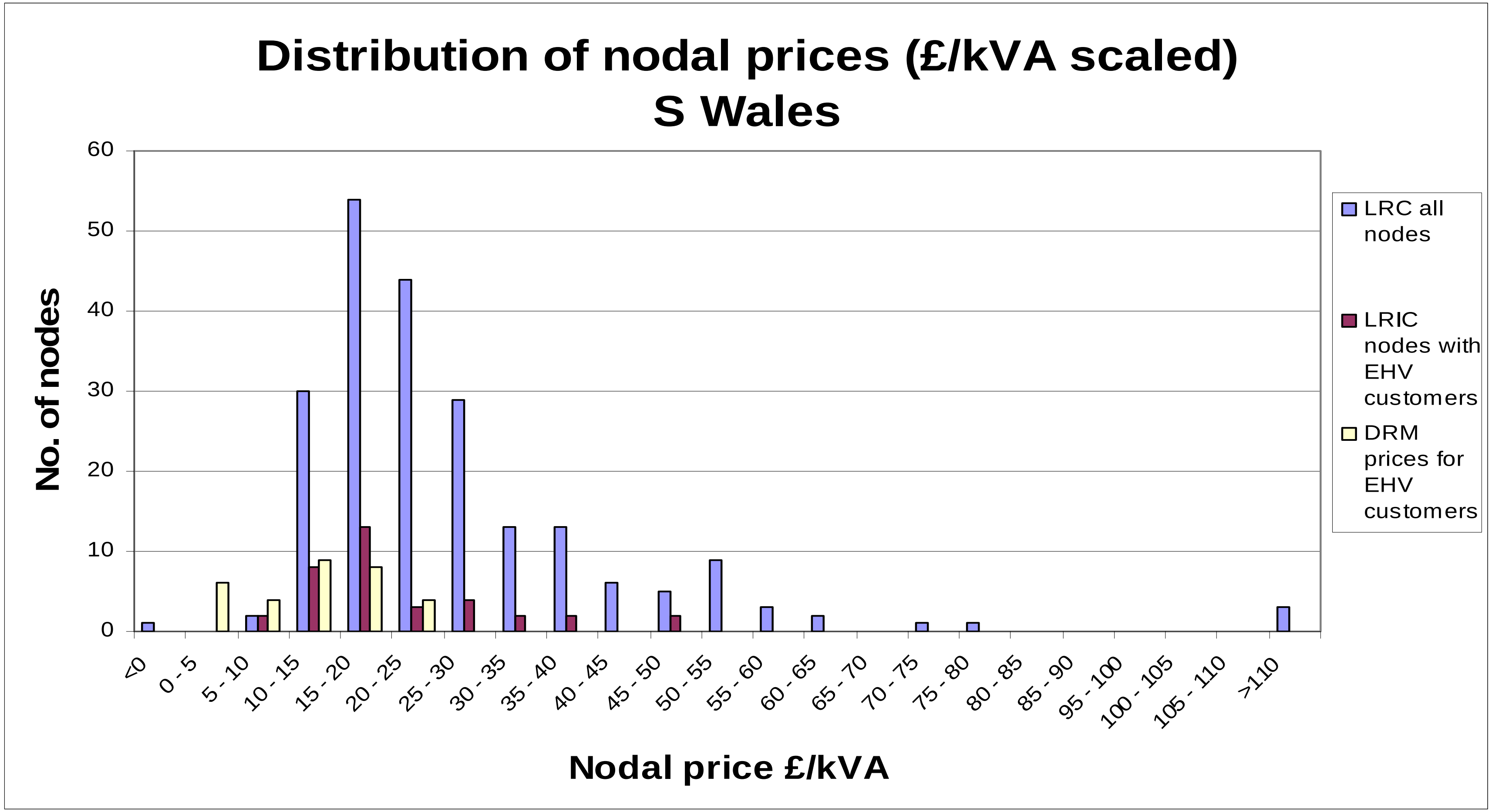
Fort James	97,736	80,334	-17.8%
Inco (Europe)	111,567	124,841	11.9%
Mainline Pipelines	52,701	52,699	0.0%
Monsanto	119,080	119,073	0.0%
PCC Texaco	944,263	944,192	0.0%
Petroplus	46,455	46,453	0.0%
Simms	16,103	16,102	0.0%
Swansea University	68,179	68,552	0.5%
Tower	50,957	50,954	0.0%
Whitbread Magor	85,518	85,516	0.0%
Dragon	477,910	477,890	0.0%
South Hook	671,637	671,612	0.0%
Cardiff Sports Village	359,330	358,349	-0.3%
Aberystwyth - Manweb	778,672	776,198	-0.3%
Total EHV sites recovery	9,247,708	9,401,348	1.7%

South Wales Generation Charges (Illustrative Only) when all generators with signed connection applications are included
Note that prices to existing generators do not change significantly

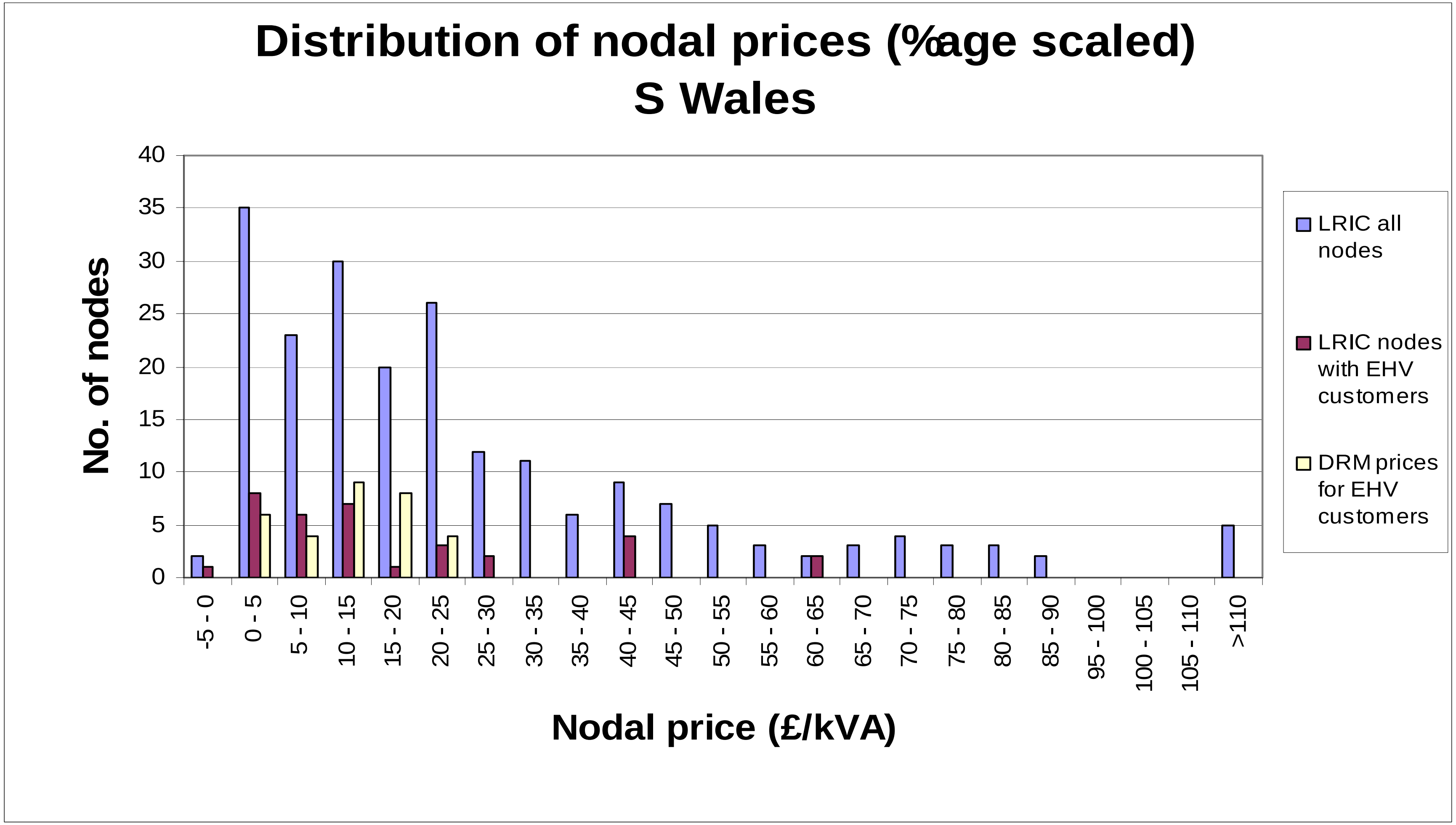
allowed income allocation 2007/08		
Mynydd y Gwair	75	MVA
Trecatti	5.1	MVA
Glyncorrwg	12	MVA
Bettws	50.7	MVA
Ferndale	10.4	MVA
Fforchnest	44.2	MVA
Trane	30	MVA
Withy Hedges	2.3	MVA
BOC Biomass	13	MVA
Blaen Bowi additional	3.9	MVA
Total additional Capacity	246.6	
allowed income per kW	2.65	
Total allowed income	£654,539.90	
kVa scaling factor	-£341.09	

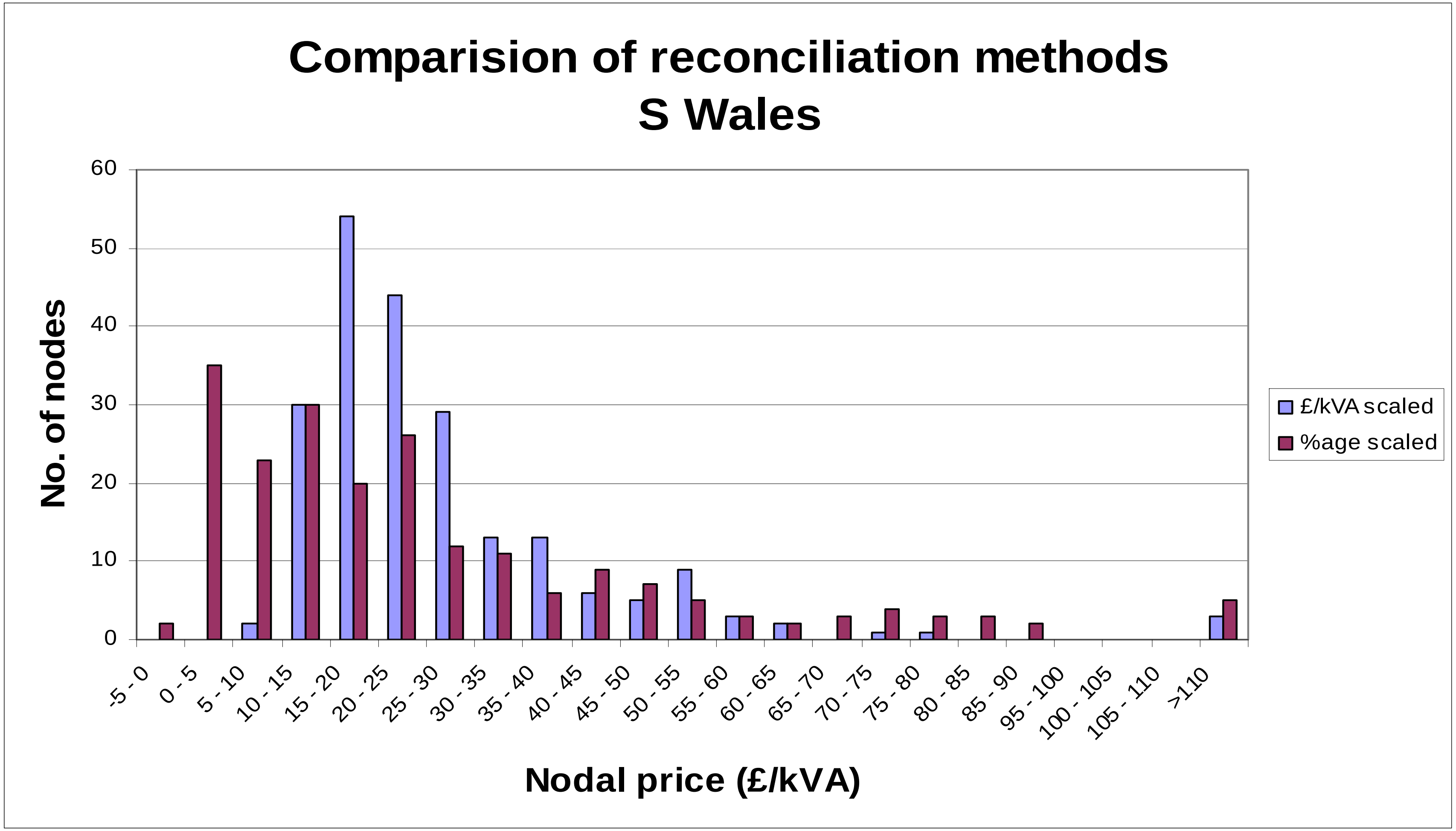
	pre scaling charge	scaling	2007/08 Final Charge	2006/07 current charge
Mynydd y Gwair	£2,259	-£25,582	-£23,323	£0.00
Trecatti	-£54,700	-£1,740	-£56,440	£0.00
Glyncorrwg	£114,011	-£4,093	£109,918	£0.00
Bettws	-£262	-£17,293	-£17,555	£0.00
Ferndale	£13,991	-£3,547	£10,443	£0.00
Fforchnest	£690,361	-£15,076	£675,285	£0.00
Trane	£12,003	-£10,233	£1,771	£0.00

Withy Hedges	-£46,809	-£785	-£47,593	£0.00
BOC Biomass	£6,262	-£4,434	£1,828	£0.00
Blaen Bowi additional	£1,535	-£1,330	£205	£0.00
	£738,652	-£84,112	£654,540	£0.00



Distribution of nodal prices (£/kVA scaled)
S Wales
No. of nodes
0
10
20
30
40
50
60
<0
0 - 5
5 - 10
10 - 15
15 - 20
20 - 25
25 - 30
30 - 35
35 - 40
40 - 45
45 - 50
50 - 55
55 - 60
60 - 65
65 - 70
70 - 75
75 - 80
80 - 85
85 - 90
95 - 100
100 - 105
105 - 110
>110
Nodal price £/kVA
LRC all nodes
LRIC nodes with EHV customers
DRM prices for EHV customers


Distribution of nodal prices (%age scaled)
S Wales
No. of nodes
0
5
10
15
20
25
30
35
40
-5 - 0
0 - 5
5 - 10
10 - 15
15 - 20
20 - 25
25 - 30
30 - 35
35 - 40
40 - 45
45 - 50
50 - 55
55 - 60
60 - 65
65 - 70
70 - 75
75 - 80
80 - 85
85 - 90
95 - 100
100 - 105
105 - 110
>110
Nodal price (£/kVA)
LRIC all nodes
LRIC nodes with EHV customers
DRM prices for EHV customers


Comparision of reconciliation methods
S Wales
No. of nodes
60
50
40
30
20
10
0
-5 - 0
0 - 5
5 - 10
10 - 15
15 - 20
20 - 25
25 - 30
30 - 35
35 - 40
40 - 45
45 - 50
50 - 55
55 - 60
60 - 65
65 - 70
70 - 75
75 - 80
80 - 85
85 - 90
95 - 100
100 - 105
105 - 110
>110
Nodal price (£/kVA)
£/kVA scaled
%age scaled

7. Model showing charge creation

7.1 The spreadsheet model used to derive charges allows further understanding of the method and is available. We intend to develop a version of this to be available to users.

8. Proposed implementation

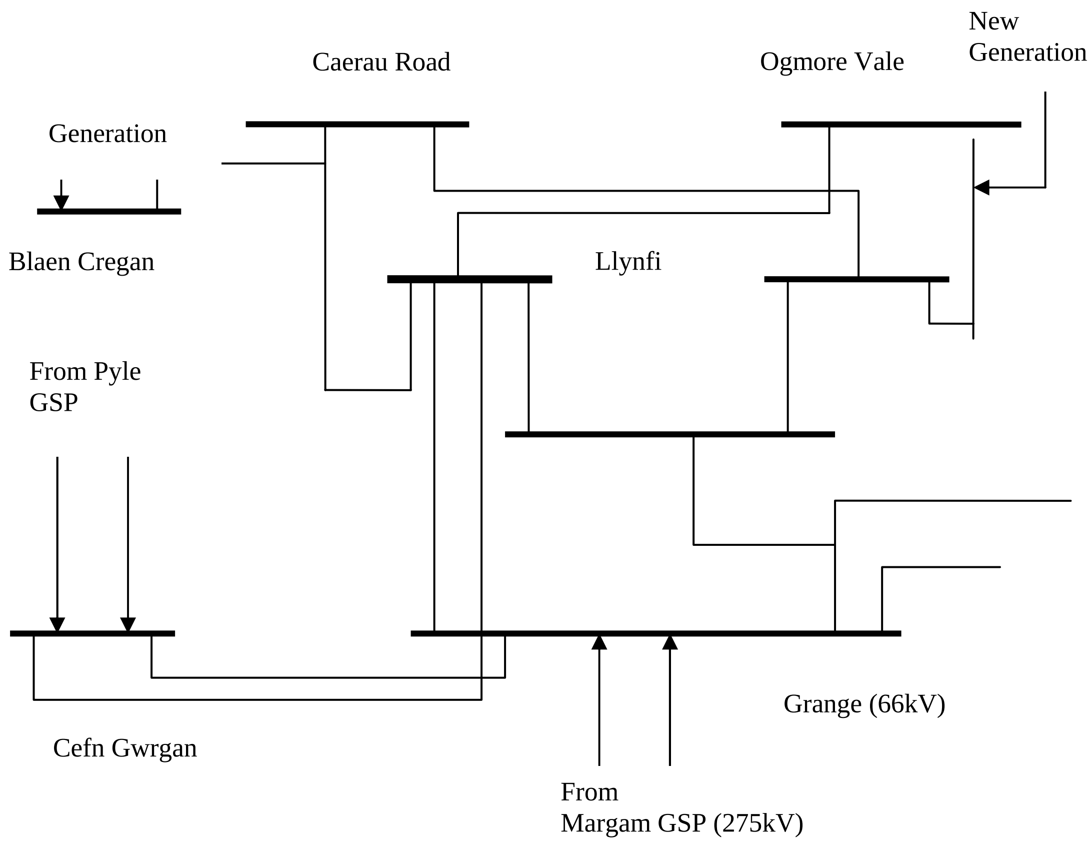
8.1 The approval of the Authority is sought to implement the revised proposals. If the Authority decides not to veto this proposal before 2nd February 2007 then it will be implemented on 1st April 2007, otherwise it is proposed that implementation will be on the 1st day of the month 5 months after a decision not to veto is made.

Attachment 1

Example of impact of connecting new generation (44MVA capacity) adjacent to Ogmore Vale substation. The price of a large load at Cefn Gwrgan changes from £749k to 928k.

Major factor in the price change at the Cefn Gwrgan node is that it becomes dominated by the summer conditions when the generator is assumed to be running. This section of network is unusual because under a single fault condition the network is supported by the closure of 2 normally open circuit breakers on the circuits towards Pyle.

After the inclusion of the additional generation the years to reinforcement on the 2 circuits to Cefn Gwrgan fall from 77 years to 33 years and 95 years to 51 years respectively.



Grange/Pyle 66kV network