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135/05: Structure of electricity distribution charges – Consultation on the longer term charging framework

Dear Mark

Please find attached our detailed response to the above consultation.

RWE believe that robust networks are required to transport energy to customers. Predictable network charges are important to enable us to offer accurate prices to our customers. The methodologies used in the calculation of network charges should therefore be clear and transparent and applied equitably to all market participants.

In summary:

We agree with the proposed principles providing that transparency and predictability are developed such that users can accurately predict the level of charges both overall and for individual groups.

The development of charging models must separate the component intended to reflect the marginal costs imposed by generation and load from that intended to secure the distributors revenue or provide an incentive for wider regulatory objectives.

An asset base definition of connection boundary is preferable to the current conceptual approach.

Any substantial changes to the present methodology that result in substantial price disturbance require longer periods of notice than currently contained in the charge revision timetable.

Before GDUoS is applied to extant distribution, the nature of the access rights that have already been acquired should be defined and appropriate buy out arrangements developed.

Further consideration of reactive power charges for generators is required as the

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present arrangements do not distinguish when generators may be supporting the system by providing local compensation.

Finally we recommend the establishment of a Distribution Charging Methodologies Forum (DCMF) to consider the detail and application of any proposed structure of charges. This should operate under the auspices of an independent chairman.

If you would like to discuss any aspect of our response, please do not hesitate to contact me.

Yours Sincerely

Terry Ballard
Economic Regulation

Structure of electricity distribution charges

Introduction

1. This response to Ofgem's consultation on the longer term charging framework for distribution charges (March 2005) has been prepared by RWE Npower plc in conjunction with Npower Ltd. It represents these companies' provisional views pending further discussion within the industry. A review of the structure of use of system charges is long overdue but it is disappointing that the consultation did not simultaneously consider the structure of connection charges since the interaction of the two sources of distributor's revenue raises a number of charging issues.

Use of System Charging Models

Charging principles

2. Broadly we agree that the charging principles articulated in paragraph 3.13 should form the basis for distribution use of system charges, although it should be made clear that the principle of simplicity should not be taken to preclude the use of relatively sophisticated models that can reflect the costs of using the distribution system. The principles of transparency and predictability need to be developed with the purpose of ensuring that suppliers and distributed generators can predict likely future charges for specific customers or groups of customers. This is necessary so that suppliers can both properly structure their charges and also ensure that economic signals are in turn reflected to specific groups of customers.

3. Such transparency should not only cover the modelling arrangements employed in setting charges but also extend to the performance of each DNO under its price control. In particular a framework is required whereby the consequence of under or over recovery of the price control target can be assessed for future movements in charges. Transparency and predictability make publication of charging models and their accompanying data essential. Publication will also stimulate debate on the appropriateness of the chosen modelling approaches which in turn should lead to improvements

4. The charging principles should also recognise that economically derived DUoS charges have two purposes. The first is to provide appropriate cost signals to load and distributed generation that will encourage efficient siting and thus economic operation of the system. The second is to enable the DNO to recover the allowed revenue that will ensure maintenance of the capital invested in the system. Different charging principles are likely to be required to satisfy each of these objectives.

5. The charging principles contemplated in the consultation paper appear to be aimed at the former objective. When considering the detailed charging issues below we suggest other principles that may impact the latter objective. The relevance of Ramsey pricing principles are considered in the consultation paper but issues of equity and the avoidance of perverse interactions with transmission pricing should also be considerations.

Model characteristics

6. The Distribution Reinforcement Model (DRM) employed by most DNOs effectively allocates the costs of the existing system between users. Whilst this may be judged a reasonably fair allocation process it does not provide any signals of future costs that are likely to arise from the connection of new load or distributed generation. Furthermore it is based on the notion of unidirectional current flows from higher to lower voltages. Additional problems are also emerging with the use of the DRM.

7. Some DNOs have modified the concept to create models that will replicate the permitted revenues in the price control under a range of market conditions. For example whilst most investment is driven by peak demands the revenue recovery permitted under the price control is structured such that 50% is a commodity charge, and 50% is linked to the demands of individual customers. These move away from the original approach of cost reflection. Moreover the load research on which the DRM is based is now extremely dated and probably no longer reflects current patterns of consumption by different customer classes.

8. To the extent that DUoS charges are derived from an economic model we would agree that the model should reflect the change in future costs and benefits consequent upon the addition (or reduction) of load and generation. The principal cost drivers would appear to be capacity and contribution to fault levels. However, the imposition of these costs must be distinguished from costs that flow from changing regulatory drivers such as network design standards (perhaps in response to a growth of distributed generation) and quality of supply standards. Costs that arise from regulatory changes should not distort the economic signals attributable to increased load and generation. Similarly incentive arrangements should also be isolated from the cost drivers that should be reflected in charges.

9. The treatment of distributed generation and load should be symmetrical in the sense that both should see the incremental costs or benefits they bring to the system, albeit that the nature of the costs may differ. A test of the appropriateness of any model is that it should be sufficiently sophisticated to accommodate both load and generation, and recognise the different support for the system that will be provided by base load and intermittent generation. An added complexity in this respect will be the intrinsically different standards for the connection of generation and load. Again it is important to distinguish between costs that arise from the regulatory backcloth, and those that are caused by incremental changes in load or generation. Only the latter of these should form the basis of the economic element of the DUoS charge.

10. The core of any economic model will be a load flow model based on the extant system. Transmission charging currently makes use of a DC load flow model on grounds of simplicity. Such a model may well be appropriate for deriving incremental costs on a highly meshed system where the main criteria will be the thermal rating of lines. However, for distribution systems where voltage may become the limiting design criterion, especially at lower voltages, an AC load flow model may be the more obvious choice. An AC model may also be more useful at identifying the costs of reactive power, which might be particularly relevant when contemplating the costs and benefits of distributed generation. In this respect consideration would need to be given to the publication of data required for the functioning of the models.

Detailed Charging Issues

Connection charging boundary

11. Rather than the choice of an appropriate connection boundary being driven by the choice of use of system model (paragraph 4.5) we would suggest that it is the definition of connection assets that should define the scope of the use of system model. A difficulty with the present boundary is that it describes a notional point in the system. Furthermore the calculation methodology in the DRM for deriving use of system charges as an annuity is similar to that for expressing the costs of the connection assets. Consequently no real distinction is drawn between the treatment of connection and system infrastructure assets.

12. We disagree that a shallow definition of connection assets assists market entry for new distributed generation. Instead it adds to the uncertainty of future costs and makes funding of any prospective scheme more difficult and potentially more expensive. One of the merits of deep connection charges is that it provided a strong siting signal. However, if Ofgem is minded to move to a shallow connection boundary then we would suggest that it should be a specific asset related boundary. Assets that are provided for the sole use of a customer would be an obvious choice for a connection boundary definition, but the prospect of future asset sharing may make such a boundary difficult to identify. An alternative might be to contemplate defining connection assets as those whose provision is contestable. In this case the basis for their charges should be the historic cost of their provision since this would be the basis of the cost if they were provided by a third party.

Charge application issues

13. Regardless of whether or not DNOs employ a common model for deriving charges there would be considerable merit in aligning the structure of charges seen by suppliers and rationalising the large number of DNO use of system tariffs. This would enable customers better to understand the basis of the charges and facilitate the development of appropriate metering arrangements. Whilst a DNO might argue for no disturbance to the structure of its particular DUoS tariffs, since this will lead to costs of reconfiguring billing systems, systems used by suppliers to validate distribution charges and bill their customers must be capable of dealing with 14 different sets of charging structures. Uniformity in the treatment of, for example, excess capacity charges would greatly reduce the administration costs seen by suppliers. The lead-time to modify systems and the attendant costs consequent upon any changes to the present practices should not be underestimated. The three months that is available following a change to the charging methodology for billing and customer services systems to be modified would be wholly inadequate if the methodology change were substantial.

14. For larger customers and distributed generation pricing signals in distribution tariffs may have a direct impact on aspects such as siting signals and time of use of the distribution networks. For smaller loads it is not essential to assume that the pricing signal must reach all the way to the end customer. Provided suppliers have a means to exercise control over certain types of load then it may only be necessary for the supplier to see the price signal and decide to what extent it can respond on behalf of its customers. Indeed this

may be preferable since otherwise there may be a conflict between the pricing signal seen by the customer and the cost burden in terms of energy imbalances that would be placed on suppliers under NETA. Innovation in this area may be encouraged if there were a specific link to the Energy Efficiency Commitment placed on suppliers.

Line Loss Factors

15. Transparency of the methods used for the derivation of line loss factors (LLF) is as essential as the publication of the Distribution Charging models. We would advocate that the calculation methodology be incorporated in the charging methodology statement that a DNO is required to publish pursuant to SLC4 of the distribution licence. LLF play a pivotal role in the settlement of a supplier's energy bill but the distributor is generally indifferent to their impact. Accordingly it is proper that suppliers are involved in the derivation of an efficient methodology that can be applied universally.

16. Without a common methodology, as is currently the situation, any comparison of GSP Group Correction Factors, or Annual Demand Ratios, will be mis-leading. Ideally LLF should reflect the technical losses associated with a particular group of customers. However, if this is not practicable then it would be better for LLF to encompass all 'losses' (including theft and other non-technical losses) so that they can be clearly defined and their relationship to the Group Correction Factor understood.

17. The difficulty in properly recognising electrical losses has implications for DNO Losses Incentives. The intention of a Losses Incentive should be that less electricity enters the Distribution Network for the same level of supply, thus reducing overall cost. The nature of the settlement process is such that it is not easy to ascertain whether a change in "lost" energy is attributable to changes in the recognition of settlement volumes, for example the inclusion in a suppliers account of volumes attributable to theft, or vacant sites, or a genuine reduction in technical losses. The DNO will receive the same reward for reducing both categories even though in the former case there is no net benefit to the system.

Scaling of Prices

18. The scaling of prices to produce the permitted revenue under the price control requires separate consideration. As we noted earlier a clear understanding is required of the principles that will underpin any adjustments to the outputs from an economic model for the purpose of meeting the revenue target. Transparency and predictability in this process is as important as transparency in the functioning of the economic models. It is likely that since much of the distribution system outside of the urban conurbations will be relatively lightly loaded and thus the marginal costs of meeting incremental demand or accommodating distributed generation may well be relatively low. Under such circumstances the revenue needed to adjust the yield from prices based on marginally derived charges could increase significantly.

19. Ramsey pricing principles would seem to dictate that these sums should fall on the least price elastic customers so as not to distort the signals seen by those customers whose consumption or siting will be sensitive to price. In general terms this implies that these costs should fall on demand customers connected at lower voltages. However, in applying such a principle other

considerations may also be relevant. A principle needs to be devised concerning the geographic area over which such costs should be recovered. There will inevitably be boundary issues between adjacent DNO or IDNO areas but it may also be appropriate to contemplate a differential application of the non-marginal charge within a distributor's area. Judicious application of the non-marginal charge might also be used to remove perversities that will otherwise exist between connection of larger generation and load at 132 kV or transmission voltages. The split of revenue recovery between generation and load may also be a consideration in this respect.

20. The transition to any new arrangements, especially if these create significant price disturbance for any group of customers, needs careful planning. Generally supplier terms and conditions will permit variations to supplier prices in the event of a regulatory driven change but these provisions are rarely deployed given the commitment to price stability. Customer reaction is likely to be much more accepting of change if notice can be given on much longer timescales than are provided for in the customary annual price revisions. Suppliers and distributed generators must have sufficient time to not only amend systems and tariffs but also to inform customers of changes that will create significant disturbance.

Generator Charging Issues

21. We are concerned that the introduction of GDUoS charges from 1 April 2005 has radically altered the viability of some distributed generation schemes. This implies that the GDUoS charge is not reflecting the costs of absorbing distributed generation reflected in a deep entry connection charge. This may be because the method of deriving GDUoS presently lacks sophistication, or because the DNO is basing its projections of future use on assumptions that are unduly pessimistic. The current use of separate "pots" for the revenues generated by demand and DG under the price control may also be creating anomalies in the economic signals that GDUoS is intended to give.

22. The consultation document indicates that all distributed generation will be subject to use of system charges from 2010. We would suggest that adjustment of future charges for sums paid by way of a capital contribution is not an appropriate approach. The deep entry connection charge was believed by both parties at the time the connection agreement was concluded to create rights of access to the distribution system for the period for which the generation remained connected. Arguably these assets have been used for subsequent reinforcement of the system. If GDUoS charges are to apply to generators connected under this regime then the appropriate approach is to value the access rights that have been acquired and reimburse this sum to the generator. This would be similar to the approach taken by National Grid at the time of the introduction of "plugs". Since the value of the access is likely to depend upon the future cost of GDUoS this might appear something of a zero sum game for the connected party.

23. The advent of GDUoS charges raises a number of issues. It would be useful if a generic approach could be found that can simultaneously recognise circumstances where distributed generation may either support the local network or impose costs. Contractually this might be achieved through a form of contract that would separately identify:
    - the connection of generation to the distribution system,
    - a liability for use of the distribution system and its associated charges,

- the provision of ancillary services including support for the local system,
- charges for reactive power where these are not covered by the ancillary services contract.

24. Under such a contractual framework charges would tend to be site specific although they might still be derived from the same charging models used for demand. Indeed this would be desirable to achieve consistency with the DUoS charges for load. For distributed generation that was price elastic, which might encompass most technologies other than those that were uncontrollable (e.g. photo voltaic cells), distorting the pricing signals through the inclusion of an element of charge that recovered the non- marginal costs of the system would distort the economic signals and thus not seem appropriate.

25. This contractual framework might either be a direct relationship between the generator and the distributor, or alternatively a supplier could manage the contract as the agent of the generator. In principle a similar approach might apply to large manageable loads.

26. In most cases GDUoS charges are based on kVA rather than kW, and a kVArh charge applied irrespective of local operating conditions. This would seem inappropriate where the operating conditions specified in the connection agreement or in the Distribution or Grid Code permit or even require the generator to operate at a power factor away from unity. In some circumstances blanket reactive power or power factor related charges my be applied even though the generator is positively reducing the costs that would otherwise be seen by the system. Locational signals in reactive charges are probably even more relevant than in active power charges.

Impact Assessment

27. Whilst it is appropriate for DNOs to play a major role in the development of the structure of their charges we are doubtful if the project will retain its impetus if Ofgem relinquishes the chair. We would also note in this context that most supply companies are part of a group that includes a major distribution business. The interests of these companies may well differ somewhat from those of suppliers that have no wires business in their group ownership. If distributors are to take the lead in the development of charging structures then It would be helpful if Ofgem would contemplate a collective license modification (CLM) that would place an obligation on DNOs to develop structures in accordance with defined objectives, parameters and time-scales.

28. We are also concerned at the statement (paragraph 5.1) that Ofgem does not view the structure of charges as regulatory policy but rather as a commercial initiative. Given Ofgem’s role under the European Directive it would seem inappropriate for the structure of distribution charges to be anything other than regulatory policy.

29. There should be close cooperation between DNOs, suppliers and customer groups on the future structure of DUoS charges. Ideally similar charging models should be adopted although the topography of different DNO systems will inevitably introduce differences of emphasis. For efficient application of

the charges commonality in metered parameters and accompanying rules is highly desirable.

Implementation

30. Whilst we support the general stance to regulation that is implicit in Ofgem's intention not to continue to lead this project we are concerned that momentum will be lost unless Ofgem continues to influence the process. We have suggested above the use of a CLM as one method by which Ofgem could exert such pressure.

31. Continuation of the ISG as an expert sounding board would still seem desirable, possibly with the encouragement of its members to bring academic input to the table as well. However, there is also a need to make the process more inclusive and to this end we would suggest the development of a Distribution Charging Methodology Forum where attendance was open to all. This might meet on the afternoons of the days when the ISG was meeting in the morning. It would be concerned more with the detail and application of any proposed structure of charges. An important feature of a DCMF is that it should have a chair that is independent of the distributors so that users can gain confidence in its ability to consider all charging issues on a level playing field. The use of a DCMF in the resolution of certain disputes that might emerge under a consolidated DUoSA (or DCUSC) might also be contemplated.