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19th August 2008

Dear Rachel,

Electricity distribution structure of charges project: decision on a common methodology and consultation on governance arrangements

SSE is not opposed in principle to the idea of common governance for distribution use of system charging. If correctly implemented this could reduce bureaucracy, increase transparency and, potentially, reduce costs.

We would, of course, wish to see the simplest, least expensive governance regime implemented. In our view, this means bringing distribution charging under the DCUSA governance, Option 1 in Ofgem's consultation paper. In developing this Option further, consideration could also be given to instigating a 'joint office', similar to Gas, for the secretariat function.

We do not believe that Options 2 or 3 are viable. Modifying the current DNO licence (Option 2) would not, in our view, provide a suitable long term framework for reviewing and maintaining a distribution charging methodology. We are not clear how the governance and change control process could be adequately captured within a licence condition. As noted by Ofgem, Option 3 would have significant cost implications for industry parties. Furthermore, it would add another level of bureaucracy to industry processes. On balance therefore, we believe Option 1 should be considered further for any common governance arrangements.

If common governance is to be taken forward, the question is then 'governance of what'? In our view, there are three options:

- Implement a common governance regime around the existing / proposed methodologies;
- Implement with a common methodology based upon long run incremental cost (LRIC) pricing (or a variant thereof); or
- Implement with a common methodology based upon Forward Cost Pricing (FCP).

Tackling each of these in turn: firstly, as we have previously argued, we believe that there is strong merit in allowing DNOs to continue to develop their own charging methodologies, as they seek to better meet the objectives of standard licence condition 13. We believe that this will provide for continued innovation, which will inevitably drive all DNOs towards best practice. In our view, such innovation will ensure that the different charging methodologies will continue to develop and provide more transparent, cost reflective price signals as networks and users change over time.

With regard to a common methodology based around LRIC, we could not support a collective licence modification (CLM) that compels us to work with third parties in bringing forward a methodology that fails to meet the relevant objectives of standard licence condition (SLC) 13 or the high level principles agreed with industry. In our view, any common methodology based upon LRIC pricing will fail to meet these objectives and principles.

We have written on a number of occasions about our fundamental concerns with LRIC based charging methodologies. In particular we have provided critiques of the WPD implemented methodology and (very recently) the proposed EDF variant methodology. We continue to believe these methodologies are fundamentally flawed and will fail to provide cost reflective, transparent charges. Furthermore, we believe that the errors in demand costs derived by LRIC, and reflected in generator benefits, inevitably means that the methodologies fail to facilitate competition. This concern over facilitating competition is exacerbated by the use of a fixed adder approach for revenue adjustment.

Furthermore, we believe that a LRIC based use of system charging methodology will be incompatible with the current 'shallowish' connection charging methodology. A LRIC based use of system charging methodology will by its nature, seek to provide full locational signals to users of the networks. As the 'shallowish' connection charging methodology already provides a locational signal, the resulting 'pancaking' will mean that incorrect economic signals are provided to both demand and generation. We do not believe changing the connection boundary to 'ultra shallow' would be a trivial exercise to undertake. More importantly, we believe such a move would be incompatible with developments in competition in connections and we also note there are a number of problems emerging with this methodology in transmission.

In contrast, the FCP methodology developed by six of the fourteen DNOs satisfies all the principles set out by Ofgem in Annex 2 of their decision letter. It strikes a reasonable balance across the high level principles and better meets the relevant objectives of SLC13 than existing charging methodologies. With regard to locational signals, we believe that it complements the signals provided by the current 'shallowish' connection boundary. Furthermore, it corrects the failings of the LRIC methodology in determining EHV reinforcement costs and it extends the analysis to cover EHV generation costs. At HV/LV it uses an extension of the COG model developed by all DNOs. Further, all of this is achieved via a single, holistic model.

FCP is already fully developed and ready to be implemented by six DNOs; there should therefore be no major obstacles in applying it or adapting it to the remaining DNOs. Given the very challenging timescales set by Ofgem to develop and implement a common charging methodology, we believe FCP represents the lowest risk option.

We have attached as an Appendix a critique of the assessment of the pros and cons of LRIC and FCP outlined in Ofgem's decision letter.

In addition to the fundamental concerns identified, Ofgem are aware of our concerns regarding how any pre-April 2005 generators can legitimately be required to pay use of system charges going forward. We will not repeat all of the arguments here (having recently reiterated them to Ofgem in our 14th May 2008 response and various informal discussions). However, it is important to reiterate that introducing GDUoS to pre-April 2005 generation, with no compensation for already paid deep connection charges, would undermine their property rights. We, along with all other DNOs, have previously explained, in some detail, why seeking to compensate pre-April 2005 generators would be impractical and unworkable. It is our very strong opinion that pre-April 2005 generators should not be subject to such charges having connected under an entirely different regime and already paid locational charges through their deep connection contribution.

Indeed, we do not believe that it is appropriate for any generators to pay distribution use of system charges. The government, the EU and most environmental groups recognise the urgent need to encourage embedded generation. Ofgem has identified this is a major part of their 'environmental' theme for DPCR5. With this in mind we believe there is a strong case for setting generation use of system charges to zero. In our view, this would provide the single biggest incentive for renewable, distributed generation to connect. Locational signals would still be provided via the existing 'shallowish' connection charges.

If a common distribution methodology is to be imposed upon DNOs then it will be absolutely essential for Ofgem to take leadership in establishing a common model. For example, the Distribution Reinforcement Models currently used by DNOs have diverged over time and hence a new, holistic, model will be required. Therefore, Ofgem must be clear on the methodology and governance to be implemented, appoint consultants (if considered necessary) to develop proposals, chair industry fora and provide swift dispute resolution.

In summary, we are not in principle opposed to the proposal for common governance of distribution use of system charging, but with the starting point being all DNOs' individual charging methodologies. We certainly could not support a CLM based upon a LRIC methodology which we believe is fundamentally flawed. If a common methodology is to be imposed, we believe that one based upon FCP represents the lowest risk option. It is already fully developed, and would better meet the relevant objectives of SLC13, for both demand and generation. However, we are strongly of the view that generation, and certainly pre-April 2005 generation, should not pay distribution use of system charges. In our view, this would provide the single biggest incentive for renewable, distributed generation to connect to the network.

If you have any queries on any of the above, please do not hesitate to call.

Yours sincerely,

Malcolm J Burns
Regulation Manager

Appendix: Detailed comments on Annex 2 of Ofgem decision letter

EHV Demand
The G3 FCP approach has been designed to remedy the demonstrable faults and weaknesses in the LRIC approach which we have previously provided to Ofgem, in particular:

1. Nodal analysis - EDF use sensitivity coefficients based on load flows under normal operating conditions. Actual costs are determined by the need to reinforce under N-1 (and sometimes N-2) contingency conditions. It is therefore the sensitivity coefficients under the contingency load flows which should be used to determine charges. A simple model (appended as an annex to this note and described previously at DCMF7 in relation to the EDF proposal) illustrates how major errors arise from using normal load flows. As far as we are aware no studies have been carried out to quantify these errors and the methodology clearly fails to carry out a proper assessment of N-1 contingency conditions. So whilst the LRIC methodology provides different nodal prices, the variation between nodes is unsound.

FCP therefore uses average rates across Network Groups. It reduces the complexity of the analysis and is being applied via the computer systems of 6 different distribution service areas. Furthermore, the results are much more readily checkable.

2. Growth Rates - The LRIC approach applies constant growth rates to all future times. However, the ability to forecast growth rates well into the future, particularly when energy prices are extremely volatile, is limited. Examination of historic forecasts and growth rates over the last 20 years shows a steady fall in the average growth rate and that locally high growth rates do not generally continue for long periods. The problem is compounded in that the Bath LRIC methodology gives a high weight to future reinforcements, a reinforcement in 20 years still carrying about 25% of the weight of an immediate reinforcement. Thus charges set by reinforcements well into the future are likely to be unsound and give incorrect messages.

In contrast, FCP considers only the next 10 years. This is a compromise between the limited number of years for which growth rates may be reliably forecast and a longer period which is desirable to enable customers to make long term investment decisions. The use of a shorter period encourages the utilisation of available spare capacity and provides a more immediate and sharper signal when the limiting capacity is being reached.

3. Charging algorithm - The Bath LRIC charging algorithm is incorrect. WPD limited their final analysis to a single growth rate of 1% thus avoiding comparative errors between growth rates. However, at a growth rate of 1% the total recovered over the 10 years prior to reinforcement is about 5 times the cost of reinforcement and some 35 times the cost of reinforcement from the time of 50% utilisation. EDF propose applying an arbitrary scaling factor to the utilisation which effectively eliminates the comparative errors and also dampens the excessive charge rates at low growth rates. However, neither treatment corrects the underlying error in its derivation and therefore there is no logical basis for the validity of the charge rates for any level of utilisation or growth rate.

FCP uses an algorithm designed empirically to give an appropriate behaviour as utilisation and growth rate vary. The same functional form (LRIC Corrected) can be derived by correcting the faulty use of annuity factors in the derivation of LRIC. A key feature of the FCP algorithm is that for any constant growth rate over the 10 year period prior to reinforcement it recovers the cost of reinforcement.

Some concerns regarding the implementation of FCP have been raised by OFGEM in their consultation document on the SP proposed methodology, in particular the use of 1%

increments up to a limit of 15%. Neither the 1% nor the 15%[1] are inherent properties of FCP but are regarded as providing appropriate increments and limit for the current growth rates.

In summary, LRIC provides nodal variations in charge rates which are likely to be volatile and, in view of the faults in methodology and unwarranted extrapolation of growth rates, cannot be substantiated. FCP provides average charge rates over Network Groups which recover predicted reinforcement costs and are more stable and predictable.

EHV Generation

Both the LRIC approach and FCP evaluate generation benefits by the same methodology as used in their approaches to demand. FCP follows the planning guidelines in determining the benefits using P2/6. Some generators claim they should receive a more generous treatment based on coincidence factors according to their recorded generation at peak demand. This could be regarded as setting a revised site specific P2/6 factor.

The most significant reinforcement cost incurred by new generation arises when the fault level capacity is insufficient and higher rated switchgear is required. None of the companies proposing LRIC have yet included fault levels in their analysis. Therefore the suggestion that the LRIC method is symmetric between demand and generation whilst FCP does not treat them symmetrically is a misunderstanding of the situation[2]. Neither the existing LRIC algorithm nor the FCP algorithm for demand can be applied directly to fault levels. When a transformer or circuit requires reinforcement for demand there is already an existing demand which is assumed to be increasing at a given growth rate. In contrast there may be zero remaining fault level capacity even when the existing generation is zero. Hence alternative methods must be derived. Furthermore there is a gross asymmetry at present levels of embedded generation in that EHV demand reinforcements are largely driven by the overall growth in demand at lower voltage levels whilst EHV generation reinforcements are driven almost entirely by new EHV generation since the impedance between lower voltage networks and EHV severely reduces fault currents from the lower voltage networks. Thus the apparent desire of Ofgem to see symmetry between demand and generation is in opposition to both the actual physical behaviour of the electrical network and the unequal balance between demand and embedded generation.

In developing an appropriate FCP algorithm for setting EHV generation charges it was seen as desirable to model the actual situation as closely as possible. In practice ‘lumpy’ generation is added to the network. Hence the introduction of a ‘test size’ generator and the probability of connection within the 10 year forecast period. Ofgem have pointed out the possibility of a drift in charge rates as the distribution of generator sizes changes and hence the ‘test size’ changes. The rate of drift is expected to be small.

In summary, both LRIC and FCP are symmetrical between demand costs and generator benefits. However, the errors in the demand LRIC will be reflected in errors in the generator benefits. As far as we are aware, FCP is the only method proposed which takes account of generator costs due to fault levels.

HV/LV Demand

The G3 Tariff model is a refinement of the COG model developed collaboratively by all the DNOs with the encouragement of Ofgem. The COG model was aimed at providing a common method as a basis for all DNOs to replace DRM[3] against which Ofgem had levelled a series of criticisms. In both DRM and the G3 Tariff model the reinforcement costs depend

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[1] Table 2, Cons - item 3
[2] Table 2, Impacts - item 4b, Pros - item 6b, Cons - item4
[3] Note, not all DNOs currently use DRM.

upon rate of growth in demand and the cost per kVA of reinforcement. Network modelling is appropriate when it is necessary to distinguish between different parts or types of network (urban, rural) and where the costs and growth of these are not recorded separately. If the costs derived by modelling differ substantially from the recorded costs then either the model is in error (most likely) or the costs are incorrectly recorded (and Ofgem would need to take action). So a network model provides no additional information, the cost per kVA is the same. If it is predicted that costs will change in the future (technological development, price of copper, etc) then the same adjustment can be applied to the recorded costs as to the network model. Similarly if higher or lower growth rates are forecast then the same adjustment can be made to the RRP forecasts as to the network model costs. Thus it is difficult to see any advantage in introducing an extraneous network model rather than working directly from recorded costs. If recorded costs vary from year to year, then some smoothing may be required to derive the average cost per kVA. A practical advantage of the G3 tariff model is that it already exists in spreadsheet form and has been assessed in some detail by all three G3 companies, with current expertise residing there.

HV/LV Generation

In the G3 approach the HV generator costs are based on the same FCP analysis as that for EHV using an appropriate ‘test size’ generator and reinforcement costs. However, the costs are averaged over all HV network groups. HV benefits are given according to the P2/6 F-factors against the demand costs at HV and higher voltage levels. Where P2/6 sets a minimum capacity for a generator to be considered to provide a benefit, it is proposed that generators of all sizes receive a benefit. In addition it is proposed that generators receive a benefit against circuit reinforcement costs at the same voltage level (this applies to EHV generators as well as HV generators).

For LV generation G3 propose to charge no costs and assign no benefits. There are no recorded costs at present and no quantified benefits.

Revenue Adjustment

G3 reviewed various methods for adjusting prices to match the allowed revenue. The single fixed adder approach can create a substantial cross subsidy if the unallocated allowed revenue is a significant proportion of the total revenue. In particular it could lead to a large part of the 132kV customers’ charges being due to the historic costs of lower voltage networks. The FCP approach of a voltage level fixed adder eliminates this cross subsidy and avoids a possible legal challenge.

IDNO issues

The G3 Tariff model is readily adapted to include new tariff classes corresponding to IDNO classes.

System wide impacts

Ofgem note that the FCP approach gives weaker locational signals relative to the nodal based models. This arises from the two main causes already described: First, the LRIC model against which FCP has been compared uses incorrect algorithms which gives rise to excessively high prices at low growth rates; secondly FCP provides an average price for each Network Group rather than separate prices for individual nodes. However, this is regarded as far preferable to having unsubstantiated differences between nodal prices arising from a flawed implementation of the sensitivity analysis.

Ofgem point out that the G3 approach only recognises generator benefits when FCP demand costs are non zero[4]. In other words it only takes account of benefits that can be quantified and are (largely) taken into account in the planning process which determines the reinforcement expenditure on the network. In our view, this is a benefit not disadvantage of FCP.

A further factor to consider is that setting charges to generators based on incremental cost models can act as a major deterrent to existing generators. Consider a network with a single existing generator where the fault level capacity is exhausted. Any additional generation would require replacement of the switchboard and all switches at a very substantial cost. Inevitably incremental costing assigns a very high charge rate to this generator. The economic argument is that if the charge is regarded by the generator as being too high, then it will move elsewhere and free up the fault level capacity for another generator that will utilise the capacity more efficiently. In practise this can result in the complete loss of a generator with no new generator on the horizon. Is this the message that Ofgem want to send out? The government along with most other parties recognise the urgent need to encourage embedded generation. With this in mind, in our view, there is a strong case for setting generation reinforcement charges to zero at all voltage levels.

Volatility
The above discussion, and the experience of LRIC models elsewhere in the sector, underlines the high sensitivity of LRIC type models' (often subjective) assumptions. This is much more the case with LRIC models than alternatives and, in turn, tends to produce very volatile changes, with substantial swings year-on-year. This is not consistent with a pro-investment climate or consistent with the DNOs obligations in regard to promoting competition.

Annex - Nodal Analysis
In principle a full nodal analysis should be capable of identifying the effects of incremental changes in loads at each load point. However, this is not what EDF propose. The proposal states that the requirements for reinforcement are determined from the appropriate N-1 and N-2 contingency analysis using AC load flows based on average load growths for the network being analysed, but the sensitivity analysis is carried out only for the load flow under normal operating conditions. This would appear to nullify the potential advantages of the full nodal analysis. We are not aware of any studies which show that the results from this method are any better (in the sense of corresponding to the case where the sensitivity analysis is carried out for each contingency case) than treating all the loads as having the same sensitivity coefficients. Consider the following highly simplified case consisting of three identical branches with two identical loads supplied from supply points at either end of the line.

S1 |-------------------- L1 --------------------- L2 ------------------| S2
B1 B2 B3

Under normal operating conditions the load in Branch 1 is 2/3 L1 + 1/3 L2, the load in B2 is zero, and the load in B3 is 2/3 L2 +1/3L1. Under contingency 1, loss of either S1 or B1, the load in B2 is L1 and the load in B3 is L1 + L2. The other critical contingency condition is loss of S2 or B3 when the load in B1 is now L1 + L2 and the load in B2 is L2. It is easy to see that the sensitivity coefficients for both contingency conditions are the same for both load points. However, the sensitivity coefficients derived from the single normal load flow would assign a 2/3 sensitivity factor to L1 and a 1/3 sensitivity factor to L2 for contingency 1. In this case assigning the same sensitivity factor to both load points is the correct treatment.

[4] Table 4 - Cons 1 (the actual wording is incorrect since benefits are given against the generator voltage demand costs and those at all higher voltage levels).

It is easy of course to produce counter examples, especially if reinforcements are required on T branches. However, the simpler analysis would seem to be generally more applicable to supply point reinforcements and the SSEPD analysis suggests that most required circuit reinforcements are part of the main ring or line linking two supply points. A full nodal analysis would of course require substantial additional computation, cause potential additional volatility, and maybe render the validation of the results unmanageable.