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RE: Methodology Options to be considered for the Implementation of Location Signals on the Island of Ireland

Executive summary

The treatment of losses and network charges is a critical issue for the SEM. The implementation of new arrangements will come at a time when the sector requires massive levels of new investment to meet government renewable targets and ensure security of supply. The design of the regime should take into account both the need for cost reflectivity *and* the importance of an investor friendly regime.

On the second, experience of operating under the current regime is a good starting point. At present, investors can find themselves committing funds to a project, only to have key drivers of commercial success change as a result of factors outside their control (e.g. new connections / disconnections) before the new project is even commissioned. This acts as a material disincentive to investment.

In thinking about the design of a new regime, while we understand the rationale behind locational pricing in other markets, BGE does not believe the pre-conditions for locational pricing to be desirable hold in the Irish market. Absent these conditions, locational pricing can actually deter investors (or increase their required return). Therefore, our first preference is for a uniform charge for both losses and network access.

However, if locational pricing arrangements are to be implemented, we would wish to see a design of regime which promotes stability, transparency and predictability – in particular:

- "location" being defined zonally rather than nodally;
- arrangements which allow new investors to fix their losses and TUOS charges for a period of time upon connection to the network;
- mechanisms which smooth changes in charges between years;
- the publication of the models used to derive loss factors and TUOS charges so that investors can conduct their own "what if" analysis; and
- consideration being given to the legacy position of generators, and how changes to current network access rights should be compensated.

In terms of the specific regimes proposed for the calculation of loss factors and TUOS charges in the consultation document, if uniform pricing arrangements are not to be implemented, our preference (again, driven by the need to be investor friendly) would be:

- for losses, a zonal charge based on scaled marginal losses;
- for TUOS, a combination of postage stamp and zonal locational charges based on a static model, with a simple and transparent adjustment to assumed cost levels to reflect spare capacity.

Introduction

The Eirgrid / SONI consultation on locational signals on the island of Ireland raises a number of questions and issues which are fundamental to investors in the Irish energy sector, as well as to the efficiency of the market. To meet government targets for renewable energy by 2020, it is critical that the Single Electricity Market evolves in a way which recognises the need for massive investment in generation over the next years. This is particularly important in the current financial climate, when securing financing for new projects remains difficult.

It is in this context which we provide comments on the consultation document. We have separated our comments into five broad areas:

- our experience of operating under the current locational pricing regime for losses;
- our views on the principle of locational pricing;
- our general comments on the approach and scope of the consultation document;
- our views in relation to the proposals on Transmission Loss Adjustment Factors (TLAFs); and
- our views in relation to the proposals for Transmission Use of System (TUOS) charges.

Experience from current regime

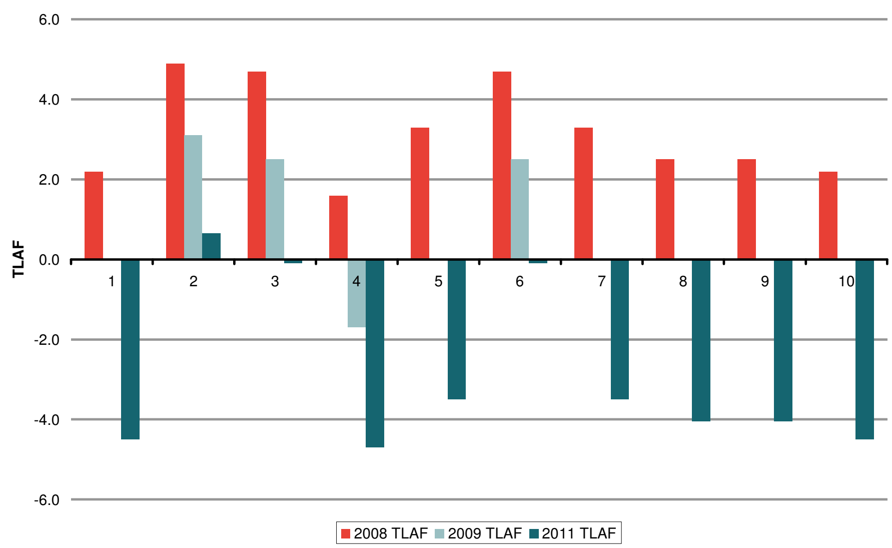
The current SEM regime involves locational TLAFs, and as a new power station investor we have experience of the issues with this regime. We believe it is critical that any new arrangements build on this experience.

The point of commitment for a sizeable new power station development can be 2-3 years prior to the final commissioning date of the plant. Under the current regime, a power station investor is therefore faced with taking investment decisions involving hundreds of millions of euros on the basis of the TLAFs proposed at that time.

However, it is perfectly possible for a change in local circumstances to take place during this 2-3 year construction period (e.g. a new plant connecting or an existing plant disconnecting). The result with the nodal regime can be that, even before a new plant is commissioned, the TLAF has moved considerably from the level on which the investment decision was taken. These movements can be extremely significant given the size of new generation plant relative to the total system.

The potential magnitude of this risk is shown in the figure below, which shows estimates of the TLAFs for 10 randomly selected nodes on the network over time.

Figure 1. Analysis of TLAFs for 10 nodes



The average change in TLAF for these 10 nodes between 2008 and 2009 was 94%. The average predicted change between 2008 and 2011 is 223%. It should be clear from the size of these changes how significant the issue is for new investors.

Moreover, there is no way for the investor to control this risk. A new power station developer faces the reality that the actions of third party generators can have a major negative effect on the value of their new investment.

As it currently stands, the regime is likely to constrain future investment. BGE believes there are a number of aspects to this problem, which we build on in the remainder of our response below:

- **TLAFs are volatile**: a nodal regime does not work well in a small system – even small changes to the system create large changes in TLAFs;
- **TLAFs are not predictable**: users have no way of confidently predicting the level of TLAFs which they may face 2-3 years in the future – and in particular, no way of carrying out their own scenario analysis based on different future sector developments; and
- **TLAF risk cannot be hedged**: there is no way for users to mitigate the risks of TLAF volatility and effectively fix their TLAF exposure for a period of time.

We therefore believe the current regime has been designed with insufficient consideration to the likely impact on investment. It is critical that any new regime builds on this experience, and is investment friendly.

Our views on the principle of locational pricing

Locational prices exist in a number of the more mature and developed electricity markets around the world – in putting together the consultation document, Eirgrid and SONI have clearly undertaken research as to the different models which have been put in place internationally.

In implementing locational prices, other markets have largely followed conclusions from economic theory which indicate that, where investment decisions on new generation are completely decentralised – that is, where entry to the wholesale market operates without material government or regulatory constraints – efficiently determined locational prices should minimise the overall costs to customers of meeting current and future load. This is because locational prices force private investors to take into account the cost impact of new investments on the *network* when taking decisions.

However, this conclusion from economic theory relies on a number of fundamental assumptions. These include, for example, that:

- users are free to make decisions as to the location of their sites in response to price signals;
- there are no material distortions to locational price signals faced by users in any other markets in which they participate; and
- there are no material non-cost related considerations in relation to locational decisions in the electricity market.

It is not clear to BGE that these conditions are met within the SEM. Below we review each criterion in turn, before turning to the conclusions which we draw from this analysis for the relevance of locational pricing on the island.

Users free to make locational decisions

In relation to the first, it is important to recognise that in order to meet targets for renewable generation, the majority of new connections to the network over the next years will be of wind capacity (and, potentially, interconnection). Both types of connection have limited – if any – scope for choice of location. The same is arguably true for other plant – where planning and zoning regulations place significant constraint on power station location.

If users are not free to make decisions as to the location of their plant, then the imposition of locational signals will not lead to an economically efficient outcome. Rather, it will simply act as a tax – transferring wealth between generators (i.e. creating both "winners" and "losers") in a manner which the generators themselves are unable to influence. At worst, this will be perceived by investors as increasing the regulatory risk which participants in the SEM have to face – and hence either discouraging investment, or at least increasing the return required to ensure sufficient investment.

No material distortions to locational prices in other markets

In relation to the second requirement, it is important to note that that the Common Arrangements for Gas have not yet been implemented, and that even within the arrangements which have been discussed, there has been no debate as to the potential for locational signals in relation to the gas network.

Looking at other electricity markets which have implemented locational signals such as GB, there are (broadly consistent) methodologies used for sending locational signals in relation to the gas and electricity networks. This means that CCGTs and OCGTs can effectively trade off their impact on the gas network and their impact on the power network. It may, for example, be rational for them to locate at an "unfavourable" zone A on the electricity network if that position is very favourable from a gas connection perspective.

Absent such arrangements, there is a clear risk that implementing detailed arrangements for sending locational signals in the electricity market results in a sub-optimal outcome. Taking the example above, the existence of just electricity locational prices might discourage plants from locating in zone A, whereas in fact this is the optimal location when both networks are considered.

It would therefore arguably be preferable to implement arrangements which either send no locational signals, or at best send aggregated locational signals. This would avoid the risk of implementing complex electricity network arrangements which aim for high levels of cost reflectivity but which, in a world where other price signals are far from perfect, end up simply representing "spurious accuracy".

No material non-cost related considerations to location

Finally, if there are important non-cost related considerations to location, then even a fully efficient set of cost-reflective locational signals may not result in an efficient outcome.

The most obvious such potential consideration for the SEM relates to security of supply. Particularly within a small system, there are good reasons for ensuring diversity of location of generation stations, even if this would impose higher costs on the network. It is not clear how this could be "signalled" using the locational pricing approaches set out in the consultation document.

Yet, if there is a general view that some locational diversity would be desirable, the implementation of the regimes proposed could either:

- result in a sub-optimal outcome in terms of generation location; and/or
- increase the perception of regulatory risk resulting from a desire for diversity on one hand (and potentially policies to ensure this diversity) and locational charges which are inconsistent with this desire on the other.

Conclusions on the principle of locational signals

As we noted at the outset, locational signals can result in an economically efficient outcome. However, for this to be the case, a number of pre-conditions need to be met. From the above analysis, it is far from clear that these pre-conditions are in any way met in the SEM – or that they are likely to be met in the next few years.

In this context, we believe it is inappropriate to continue a policy of further refining and extending locational signals. Indeed, we believe that to implement the locational signals proposed in the consultation document could adversely affect the investment climate in the market, at a time when massive investment is required and the economic conditions to support that investment are, in any case, weak.

Our first preference, therefore, would be for the implementation of uniform charging arrangements for both TLAFs and TUOS. We believe this would best support the future evolution of the SEM over the next critical years. We note that, according to ETSO, only 5 countries in Europe (GB, Greece, Norway, Romania and Sweden) have actually implemented locational pricing.

However, for the sake of completeness, in the remainder of this document, we set out our views on the different proposals for locational pricing set out in the consultation document.

Comments on the approach and scope of the consultation document

In this section, we present our comments on the consultation document in three areas:

- the assessment criteria set out in the document;
- the breadth of the definition of a "regime" considered in the document; and
- the depth of assessment of each of the proposed regimes.

Criteria for the regime

The consultation document sets out a number of objectives for the regime as articulated by various stakeholders in the project.

We believe the list of objectives is broadly representative. The individual objectives can arguably be placed into two broad groups:

- those relating to **economic efficiency**: these would include the objectives relating to cost reflectivity, short and long term efficiency, and consistency (numbers 6, 5, 1 and 7 respectively);
- those relating to "**investment friendliness**": these would include the objectives relating to transparency, predictability and volatility (numbers 2, 3 and 4 respectively).

It is important to note that there is an inherent tension between these two groups of objectives. For example, given the complexity of the transmission network and the range of potential future patterns of generation and load which may be observed, ensuring absolute cost reflectivity would almost certainly involve a very complex arrangement, and a resulting loss of transparency and predictability. Similarly, the most transparent and stable regimes are likely to involve over-simplifications of the drivers of network costs.

The consultation document recognises the "sometimes conflicting nature of these objectives" and notes that "an evaluation criteria to rank various options in term[s] of how each meets the primary objectives" has been undertaken.

However, this evaluation is simply a very high level assessment of each of the proposed regimes against these individual criteria. There is no formal consideration of the implications of this trade-off.

BGE believes this is an important omission. In particular, given the future need for renewables generation investment in the sector, it is important that the importance of an "investment friendly" regime is recognised. It is easy for regulatory debates to focus excessively on the need for accuracy and cost reflectivity – these criteria are important. However, it is also important that these debates are balanced against the short term requirements of the sector as a whole, and the broader objectives of energy policy. The customer will not benefit from a regime which is well designed from the point of view of cost reflectivity but which fails to encourage investment to guarantee security of supply.

Definition of a "regime"

The consultation document sets out a number of different "approaches" to charging for losses and for access to the network. However, each of the approaches discussed focuses very much on the "mechanics" of the derivation of locational charges.

While this is clearly an important aspect of any regime, there are other important aspects which are not covered in the paper and which will be important, not least to ensuring that the investment climate remains positive.

We have already highlighted that, based on our experience from the existing regime, volatility is a key issue. The extent to which arrangements ensure that charges are not volatile is also a decision criterion mentioned in the consultation document.

BGE agrees with the importance of this criterion – serious consideration should be given to mechanisms which smooth volatility. In particular, arrangements should be avoided which create the risk for parties just having made an investment that access conditions rapidly worsen as a result of a third party's subsequent investment (over which they have no control).

However, no explicit consideration is given in the consultation document as to how this criterion should be fulfilled. A number of mechanisms with desirable properties – for example, balancing the need for cost reflectivity with the importance of investor certainty – could be implemented alongside any of the regimes proposed in the document. Options include:

- **smoothing of tariffs between years**, such that large changes in tariff or factor levels are implemented over a period of years (such arrangements exist in relation to gas network charging in Northern Ireland, where a cap on annual increases / decreases is imposed); and
- **fixing tariffs for a certain period** (e.g. 5 years) at the point of connection to the network, with a return to variable tariff levels thereafter (a scheme of this nature is one of a number of proposals currently on the table for reform of the GB electricity network access charging arrangements, and Ofgem has in the past expressed support for similar schemes[1]);

Beyond this, BGE believes a number of other aspects of the regime as a whole should be considered. These include:

- **treatment of legacy rights**: there is no consideration given in the document to the legacy position of existing generators on the system. In the market to date, a number of parties have made investments in generation assets on the basis of the current arrangements. The value of these investments is critically dependent on the cost of access to the network, and particularly to changes in the differentials in access prices between generators[2]. Changes in the methodology for charging for access rights can therefore amount to expropriation of value by the TSO / regulator. It is important that, in considering any change to the regime, the impact on existing parties is taken into account. If it is not, first it opens the possibility of legal challenge, and secondly – and more importantly – future parties investing in Ireland will build in a perception of the risk of regulatory expropriation into the rewards they require to fund investment. This will only serve to increase the costs to customers in the long run;
- **transparency of arrangements**: in order for network users to be able to respond effectively to the locational charging regime, they need to be able to understand the likely impact of different future scenarios for sector evolution on charges. In this way, just as they can factor future scenarios for fuel prices into their investment decisions, they can take their own commercial judgements on the level of transmission charges and build this into their investments. To do this, however, it requires that the methodology chosen is clear and objective (we return to this below in considering the individual regimes considered) and it also requires that the tools and models used to derive charges are *publicly available* for users to undertake scenario analysis. Irrespective of the regime chosen, to meet its objectives, it is critical that models are public (we note that other TSOs, such as

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1 In their approval of the arrangements put in place for GB access charging, Ofgem noted that work could be undertaken "to enable parties to secure longer term access rights and choose to fix their use of system charges for periods longer than one year."

2 Changes in the total level of access payments (driven, for example, by changes in the total allowed return of the asset owner) should – within a competitive market – be passed through to customers in their entirety.

National Grid in the GB market, make their charging models public for just this reason); and

- **transition issues:** the implementation of a new locational tariff and TLAF methodology would represent a major change for the sector, the intention of which is to influence users behaviour. Once in place, new users may be able to adjust their prospective behaviour (i.e. where they think about connecting) given the regime – although we note above that we believe in the next years, few generators will effectively have this choice. However, assuming they did, to avoid the new regime imposing windfall losses and gains on existing users, it will be important to allow users to adapt their behaviour to the new regime over time before it is fully implemented. This may mean a transition period during which the scheme is phased in with locational signals strengthening gradually (similar transition arrangements have been implemented in GB, in relation to both transmission and distribution charges), or a lead time between the decision on and implementation of the regime.

Depth of regime assessment

Finally, in relation to the general approach taken in the consultation document, we note that the evaluation of the different options appears, at present, very cursory. For example:

- there would appear to be no indication of differentiation on "transparency" or "predictability" of any of the TUOS charging models – whereas in reality, the approaches involving a dynamic model are significantly more subjective (and hence less predictable and potentially less transparent) than the other approaches; and
- there would appear to be no consideration of the impact of this subjectivity on the expected level of cost reflectivity of approaches using a dynamic model.

We return to these specific examples below – however, as a general point we note that for such a serious topic, it would be expected that the TSOs and regulators would carry out a more in depth qualitative and/or quantitative assessment of the options, as Ofgem typically does through its Impact Assessment process. Simply labelling options as having High, Medium and Low correlation with decision criteria, without providing a serious rationale behind the allocation is not consistent with best practice.

Comments on options for TLAFs

As noted above, our first preference would be for a uniform approach to charging for system losses.

Of the remaining locational approaches set out in the consultation paper, BGE believes that a zonal approach would be preferable to a nodal regime.

While a nodal regime can be argued to be more cost reflective (provided the underlying model and assumptions used to generate the TLAFs are representative of the system), we believe a zonal regime would have a number of important objective advantages – for example:

- it makes locational price signals considerably **more stable**. For any given node (i.e. for any given investment) the TLAF can be highly sensitive to changes in generation and demand at other neighbouring nodes. This can mean a high risk of a new investment being impaired as a result of events (e.g. the connection of a new generator, or a disconnection) which are completely outside the control of the new project. This is not consistent with the need to secure massive investment in the sector. A zonal regime overcomes this problem by averaging (similarly valued) TLAFs, meaning that for any given node changes are more gradual (unless zonal boundaries are redrawn); and
- it also makes signals **more transparent** and **more predictable.** Because of the effect highlighted above, to predict the future evolution of TLAFs within a nodal regime, investors and potential investors have to consider the probability and timing of other individual projects in the vicinity being connected or disconnected. Indeed, early in the lifecycle of a project, new investors may be considering connecting at a node for which no TLAF has even been calculated. With a zonal regime, predicting the TLAF which will apply for any given project, and predicting how that TLAF will evolve is easier, because it is the aggregate position of the zone versus the rest of the network which is important, rather than the development of individual projects.

We note in this regard that in the GB market, there are 20 charges for generation TUOS charging[3]. A zonal rather than nodal regime wash chosen in GB for similar reasons to those highlighted above. If the size of a GB zone is taken as a reasonable trade off between objectives of cost-reflectivity and transparency, the island would have at most 4-5 zones, and possibly fewer

The consultation did not consider the temporal definition of TLAFs. At present, TLAFs are defined at the year ahead stage for the forthcoming year, and they are defined on a monthly basis, with a different factor applying during the day and during the night.

BGE believes that continuing to specify a different TLAF for the day and night risks creating TLAFs which are inaccurate.

The TSOs' predictions of system conditions 12+ months ahead of real time are likely to be subject to a wide range of important uncertainties (e.g. the oil price in December next year). To decompose 12+ months future forecasts of system conditions into night and day may appear to create more accuracy, but may actually result in TLAFs which are inaccurate as a result of forecast errors (it is arguably easier to estimate system conditions in 12 months time over a whole day than to attempt to estimate day and night conditions). Equally, it is not clear that day and night are more important determinants of system conditions than weekday and weekend.

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[3] There are no locational loss factors in the GB market – hence, we consider TUOS charging zones as a reasonable comparator.

We believe that there would be little loss of cost reflectivity, and a large gain in stability, transparency and predictability, if zonal TLAFs were calculated for each day of the month for the forthcoming 12 months.

Comments on options for TUOS

As with losses, for the reasons described at the outset of this response, our first preference would be for a uniform approach to charging for system access.

We have given the non-uniform options set out in the consultation paper serious consideration, and we believe that each of them have major drawbacks when evaluated against the decision criteria set out in the document.

Our second preference would therefore be to adopt a variant on one of the models suggested in the paper. In what follows, we set out our views on the models presented in the consultation paper, and then conclude by describing our second preference option.

Postage stamp with discounts

This model, as described in the consultation document, appears interesting. However, the description is not sufficient to allow us to evaluate the model properly. For example, the methodology used to assess which locations are "favourable" is not clear and, in the absence of further information, appears likely to be highly subjective. Equally, it is not clear what proportion of the network could be defined as "favourable".

Without further information, it is difficult for us to form a view as to whether we would support this model. If the decision criteria could be made objective, transparent and predictable, the model may have desirable properties. We therefore believe that more work should be done to define this option before the final evaluation is carried out. To dismiss the model at this stage could be to overlook a beneficial regime.

Locational charging vs. locational plus postage stamp models

The remaining charging options can be differentiated according to whether they involve:

- fully locational charges or a mix of postage stamp and locational charges; and
- a static or dynamic network model.

In relation to the first of these, we believe the appropriate choice is relatively clear – there are strong reasons which have been accepted by a number of regulatory authorities (including Ofgem in the GB market) to adopt a mixed postage stamp and locational approach.

The economic rationale for locational signals rests on the ability of parties to respond to prices in choosing *between* competing locations on the network for connection. Therefore, it is the *relativity* between prices which is important – not their absolute level. The absolute level of charges will evolve over time in line with the allowed revenue of the transmission company and the charging base.

The network model used to derive locational charges will produce a set of prices which embody certain relativities between nodes or zones. For example, zone A may have a charge of €10/kW and zone B may have a charge of €15/kW. If the network model is an accurate reflection of the underlying characteristics of the network, it is the differential between zones A and B which is important – in other words, participants should recognise that locating in zone B will impose a higher cost on the network (by €5/kW over a standard asset life) than locating in zone A. The absolute level is less important from an economic efficiency perspective.

Now suppose that these charges are insufficient to recover allowed network revenue given the charging base. Suppose that there is 100kW connected in each zone (giving a total revenue of €2500) but that total allowed revenue is €5000.

If charges are to be fully locational, the per kW charges must be multiplicatively scaled to recover allowed revenue. In other words, the €10/kW and €15/kW become €20/kW and €30/kW (which collectively recover €5000). However, the locational differential between zones A and B would then be €10/kW. Effectively, setting charges in this manner would exaggerate the cost to the network of locating in zone B relative to zone A.

Provided the network model is a good representation of reality, the €2500 of additional revenue required over and above the €10/kW and €15/kW charge levels is not driven by the location of connections. There are clearly a large number of elements of TSO cost which do not have locational cost drivers – for example:

- network opex; and
- the return on existing assets.

If no clear cost driver can be identified for these costs, economic theory suggests that they should be recovered in the "least distortionary" way possible – in order not to influence user behaviour in an arbitrary manner.

Locational charging is clearly distortionary – if it did not influence user behaviour, there would be no logic to its implementation (a point we made at the outset). In the absence of a full Ramsey pricing approach, recovery of these charges through postage stamp charging is arguably the least distortionary option.

Under this option, a uniform amount is added to all charges in order to recover allowed revenue. In the example above, the final charges would be €22.5/kW and €27.5/kW respectively (i.e. the original locational charges combined with a €12.50/kW postage stamp). These charges recover the total revenue requirement of the network (€5000) but also maintain the differential of €5/kW between the zonal charges. In a competitive market, the postage stamp element of the charges should be passed through to all customers, and therefore should not distort generator behaviour[4].

Static vs. dynamic model

The other dimension of choice set out in the consultation paper relates to the use of a static or a dynamic network model.

Our understanding of the consultation paper is that the key difference in these models (as described) relates to the treatment of spare capacity. Specifically:

- the **static model** assumes that any incremental injection to the network results in an immediate reinforcement requirement – and hence implicitly assumes that there is no spare network capacity; and
- the **dynamic model** assumes that an incremental injection to the network will bring forward planned reinforcements, but that the need for reinforcement may remain in the future – implicitly, therefore, the model acknowledges the possibility of spare capacity.

On this basis, given that there clearly will be spare capacity in different areas of the network, the dynamic model appears more attractive from a cost reflectivity viewpoint. The static model – as described – would exaggerate the cost of connecting in locations with spare network capacity.

However, BGE believes there are important drawbacks to the dynamic model:

- it is highly subjective and therefore relatively **non-transparent** and potentially **non-cost reflective** – the model requires an assumption on base network growth, and on the base network investment plant to meet this level of connection growth. Then, for any new injection on the network, a view is required on the number of years by which a new connection would advance new investment. All of these assumptions will, in reality, be based on engineering judgement and will therefore be subjective, and potentially inaccurate;
- it is therefore **difficult for participants to predict their level of charges** into the future – as a result of the subjective assumptions required, it is difficult for participants to undertake sensible "what if" analysis – a key requirement if charges are actually to influence behaviour. In order to do such analysis, participants would have to second-guess the engineering judgements of the TSOs, and would have no confidence as to whether their guesses are likely to result in charges close to those which the TSOs would derive;
- **charges will not be stable** – indeed, since the network model explicitly recognises spare capacity, charges will follow a "saw tooth" pattern. When there is significant spare capacity in a given location, charges will be relatively low (as the need for reinforcement will be in the future). As the level of spare capacity reduces, charges will rise until such time as capacity reinforcement is required for

4 It may arguably distort customer demand, but since electricity demand is relatively insensitive to price, the overall impact on economic welfare should be low.

the next connection. Then, once this connection has taken place, charges will fall again as there will be spare network capacity (as a result of lumpy transmission reinforcements); and

- the level of **charges can become increasingly volatile when new connection growth is low** – during the debates on the use of a dynamic network model for distribution charges in the GB market, it has been highlighted that there is a risk that charges become volatile for areas of the network with low growth. This could be a frequent occurence on the transmission network over the next years, as new generation will typically be in different locations to existing plant. In such circumstances, there is a risk that counterintuitive price signals are sent (with low growth areas of the network facing high charges).

In contrast, at least in terms of transparency, stability and predictability, and potentially also in terms of cost-reflectivity we believe that the static model is preferable. For a number of the reasons outlined above, National Grid moved away from the use of a dynamic model in relation to gas transmission charging during its 2007 review of methodologies.

However, we remain concerned that the static model as described does not take spare network capacity into account. Therefore, we propose the adoption of a variant on this methodology. We describe this variant in more detail below.

Our second preference model

In the light of the above analysis, among the regimes based on locational pricing, our preference would be:

- **for a mix of locational charging and postage stamp charging; and**
- **for a zonal definition rather than a nodal definition (on the same rationale as we set out for losses – and again, as has been accepted by a number of regulators internationally).**

In terms of modelling approach, our preference would be to adopt the static model, but to factor in the existence of spare capacity through a simple and transparent mechanism that preserves the benefits of the static model.

Such an approach was adopted by National Grid in the late 1990s / early 2000s, and involved the estimation of a "spare capacity factor" which was applied to investment costs in the model in areas of the network where it is clear there was spare capacity.

Applying such a factor to investment costs reduces the cost which the model estimates to result from incremental injections of power and therefore reduces charges to users. However, in contrast to the number of subjective and interacting engineering judgements involved in the dynamic modelling approach, the estimation of a single factor is much more transparent and arguably even more predictable. Equally, the application of such a factor would allow for the evolution of charges to be more gradual – and to avoid the “saw tooth” pattern which would result from the dynamic model.

If you have any queries inrealtion to any of the comments made please let us know.

Yours sincerely,

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