Executive Summary

ESBPG welcomes the opportunity to contribute to this discussion of the potential future form of TUoS and TLAF charging. We believe that the primary objectives identified by the RAs are reasonable and appropriate. We agree with the RAs that some of these primary objectives (e.g. transparency and cost reflectivity) conflict and thus we would wish to stress the importance of a balanced and pragmatic approach. ESBPG also believes it is important for the RAs to take into account wider practicalities and public policy objectives as they relate to the energy market.

ESBPG understands the economic merits of locational approaches to network related charging and believes it is important that these are applied appropriately. To this extent, ESBPG believes that the current form of TUoS charging represents a reasonable approach to long term network related charging. However ESBPG strongly believes that the current Losses charging regime has serious flaws and requires fundamental change.

ESBPG believes that the current review is timely and that the volatility, unpredictability and incorrect cost signals in the current regime pose unacceptable risk and commercial outcomes for existing and potential new entrant generators operating in the SEM.

The charging regime needs to specifically take into account the requirement to make the Irish market an attractive location for generators to invest. A TUoS and Losses charging regime that unreasonably increases the risk of project viability will deter lenders and investors from the Irish market.

ESBPG does not believe that the 4 options indicated for Losses charging in the Consultation document substantially and appropriately address the key problems with the current Losses charging regime. With this in mind, ESBPG has identified the following 3 key features/principles which it feels should inform <u>any</u> future model of Losses charging:

(i) sharing of cost of transmission losses between generation and demand;

(ii) recognition of fixed and variable losses within the charging structure;

(iii) more cost reflective TLAF differentials, without the distorting (and magnifying) effect resulting from the incremental marginal cost approach.

Having carefully considered all of the proposed models, and taking into account all of the various policy objectives, ESBPG strongly favours a postalised losses charging regime.

While favouring a postalised system, we recognise that the RAs may wish to retain a locational charging element. In the event that this is deemed necessary, ESBPG has also identified a potential alternative model (a more workable variation of Option 4) which we believe to be worthy of consideration.

ESBPG recognises this Consultation is likely to produce a range of additional proposals from across the industry and ESBPG is happy to engage in further constructive dialogue with the RAs and the wider industry to identify an optimal solution.

Any such solution must offer a stable, predictable cost signal regime which does not penalise an existing generator, or a new entrant, for responding appropriately to a price signal, or for actions of another party outside their control.

Introduction

This response presents the views of ESB PowerGen (ESBPG) in response to the consultation document issued in May 2009 and titled "Methodology Options to be Considered for the Implementation of Locational Signals on the Island of Ireland". ESBPG welcome the opportunity to be able to contribute to the review and future development of this important element of the market arrangements and looks forward to further participation with the Regulatory Authorities and the wider industry as:

(i) all potential options for the future allocation and charging of Transmission Use of System (TUoS) costs and Transmission Losses (Losses) costs are identified;

(ii) the individual and relative merits of all the identified potential options for TUoS and Losses charging are assessed; and

(iii) Options for each of TUoS and Losses charging which are most consistent with the relevant regulatory and market objectives but also the wider interests of the Irish economy are determined.

The understood objectives for TUoS and Losses charging

The RAs set out their objectives for the review in Section 3 of the Consultation, indicating 7 key factors: (i) efficiency of network use and investment, (ii) transparency, (iii) predictability, (iv) lack of volatility, (v) efficiency of short term dispatch, (vi) cost reflectivity and (vii) consistency of treatment of generation and demand

ESBPG believes these, taken together with the wider objectives of the SEM and wider public policy, are appropriate objectives to assess the merits of different options for TUoS and Losses charging; and welcome to the fact that they reflect the key concerns articulated by respondents to the industry Questionnaire as reported by the Regulatory Authorities at the seminar held in June.

We note that the RAs acknowledge that these objectives can be conflicting (an obvious example being transparency vs. cost reflectivity) We believe this is a fundamentally important point because it highlights the need for the structure of each of TUoS and Losses charging to address these conflicting needs/objectives in an appropriately balanced and reasonable manner. To this extent we also believe that in revising the form of TUoS and Losses charging applied within the SEM, it is equally important to recognise the wider policy objectives for the energy market in Ireland such as the sustainable encouragement of investment in the different regions, promotion of renewable generation and operation of environmentally beneficial technologies and practices such as new more efficient, less carbon emitting generation and improved efficiency of energy use. Clearly, the RAs should also take into account the objectives for the SEM itself as a whole, specifically:

To deliver an efficient level of sustainable prices to all customers, for a supply that is reliable and secure in both the short and long-run on an all-island basis, by

- ensuring a secure supply of electricity;
- promoting competition in the electricity market;
- minimising transaction costs for participants and customers;
- fostering the use of renewable, sustainable or alternative energy sources; and
- enabling demand side management.

as well as wider public policy considerations.

Overview of ESBPG's view of the current TUoS and Losses arrangements

ESBPG understands the economic arguments for implementing locational based charging methodologies for both Losses and TUoS. This objective of allocating costs upon those who give rise to them and/or who are best positioned to influence them is intended to deliver the most efficient market outcome and, in the long-term, provide for the most efficient prices for energy users. ESBPG also supports the recognition provided in the consultation document that the arrangements for the allocation of the costs of investment in the Transmission System (through TUoS) need to be considered together with the allocation of costs associated with the use of the Transmission System (Losses) in order that a consistent set of charging methodologies can be developed so as to reflect the linkage between the two issues as being at different parts (short-term versus long-term) of the same continuum.

Furthermore, ESBPG equally believes that it is important that charging arrangements should provide appropriate levels of incentives for all relevant parties and that these should not create unduly high costs or commercial barriers which might undermine wider energy policy objectives.

ESBPG also acknowledges the merits of network charges containing a locational element reflecting the impact of generation and demand siting and operating patterns on the investment and operational costs of the transmission network. However, in the context of above, ESBPG believes that

(i) TUoS charging (with the possibility of some refinements) largely strikes the appropriate balance with other objectives such as predictability and stability – as such ESBPG believes the current form of locational TUoS should be retained and applied across all participants in the SEM;

(ii) Losses charging currently does not strike the right balance between cost reflectivity and other key objectives such as predictability and stability – as such ESBPG strongly believes Losses charging requires substantial reform

There are three key features of the current Losses charging regime that ESBPG believes are critical to address in any future Losses charging regime, namely predictability, stability and cost reflectivity. The current regime does not provide these and worse, applies incorrect cost signals which impose unpredictability and volatility to unduly disproportionate levels and which substantially raise project costs and project risks for all generators, particularly new entrants.

In particular, a generator who responds to a signal to locate at a particular location can within a short period, even before the plant is in commercial operation, be seriously disadvantaged by an immediate adverse change in the signal in response to the decision to locate. This is clearly an unacceptable commercial risk and the characteristics of any charging regime must not give rise to this perverse outcome.

We note that for a typical modern efficient CCGT plant, a 1% change in TLAF will result in an annual reduction in margin of c. € 2 Million, due to reduced pool and capacity income, assuming the TLAF did not impact on its merit order. We note that TLAF variations across the island can be of the order of 10%.[1] This 10% change alone would represent a reduction in revenue of at least € 20 m / annum for a modern CCGT in a best case scenario. In a realistic scenario, the plant would see a much greater reduction in revenue as the penal TLAF would push it down the merit order to such an extent that its production would fall off dramatically.

Furthermore, the incorrect cost signals lead to inefficient dispatch. This inefficient dispatch of most economic generation will increase financial and environmental costs to the consumer. We are convinced similar issues are faced by all other new entrant plant many of which are renewable and critical to meeting political commitments to 2020 environmental targets. Without adequately addressing these in a future Losses charging regime there is a genuine risk that wider energy policy objectives for the environment and investment in the Irish energy market may be undermined.

[1] For example the TLAF at the Aghada node where new plant comes on stream in 2009 and 2010 was 1.047 in Jan 2009 and is as low as 0.957 at the end of 2009, with even lower indicative numbers published for 2011.

TUoS Charging regime

Whilst one could argue there are aspects of TUoS which could be refined, ESBPG believes the current regime provides an appropriate form of locational charging. In ESBPG's view, it reflects the need given a shallow definition of connection boundary for suitable long term cost signals to generators for siting and closure in order to support efficient network investment. ESBPG believes these locational signals have by far the greatest impact on efficiency of both long term network investment and long term network operation costs (constraints, losses etc).

Furthermore, ESBPG believes the current TUoS regime strikes the right balance across the primary objectives as set out by the RAs in section 3 of the consultation document (e.g. they are support efficient network investment, are predictable, are stable, are cost reflective, and are applied consistently to generation and demand); and that it both recognises practical realities, and fits within the wider public policy objectives in relation to the energy market. Thus ESBPG believes that the current locational form of TUoS is appropriate, should be retained and should be applied across all parties within the SEM. Should the current regime need to be changed, the new regime should as a minimum retain or enhance current levels of predictability and stability.

Losses Charging regime

However, ESBPG does not believe that the current regime for setting and charging Losses represents a similarly appropriate balance. Nor does it provide a consistent alignment of the resultant short term locational signals for generation operation versus the prevailing long term cost signals for generation entry timing and location, and exit. Furthermore, in ESBPG's view, it currently fails to meet most of the primary objectives set out by the RAs as its criteria for assessment in section 3 of the Consultation document. Specifically:

(i) efficiency of network use/investment – to the extent this is deemed important, there is no incentive on the TSO to invest in the network to reduce losses;

(ii) transparency – the detailed calculation of the TLAFs underpinning Losses charging is not visible to market participants;

(iii) predictable – due to the complex nature and lack of transparency of the calculation, it is highly unpredictable for all market participants;

(iv) volatility – the current Losses charging methodology derives highly volatile TLAFs between years and within year potentially “flipping” profitability from year to year and creating high operational uncertainty and thus costs, especially for new entrants;

(v) efficiency of short term dispatch – the current TLAF methodology does not reflect the impact of intermittent generation on losses and there is a misalignment between daily generator bid (P/Q) submissions and day/night TLAFs which leads to inefficient SEM bidding due to ex-ante uncertainty of dispatch and thus guessed inclusion in bids;

(vi) cost reflectivity – the methodology is currently based solely on marginal cost and thus overstates the impact of generation and demand patterns on network losses; and as such overstates TLAF differentials; i.e. it applies a marginal cost over the full range of load which is both disproportionate in impact and incorrect in principle;

(vii) equal treatment of generation and demand – currently only generation is directly exposed to TLAFs and Losses charging.

Thus it is essential that the current Losses regime be reformed, in order to address the above deficiencies in a balanced, pragmatic and appropriate manner. For example, it is critically important that any Losses charging arrangements be reasonably predictable year on year and not unduly volatile. Failure to meet either of these objectives in any substantial manner will continue to create increased uncertainty in forward revenue streams for all generators, potentially increasing risks faced by existing generators and making financing future power projects more difficult, particularly for smaller entrants.

Detailed discussion of the current Losses Charging regime and thoughts for reform

In preparing this response, ESBPG has given careful consideration to the four options presented for the allocation of the costs of Losses, taking account of the international experience provided within the consultation paper and ESBPG's own experience of operation in the Republic of Ireland both pre- and post-implementation of the Single Electricity Market (SEM).

The RAs outline 4 potential Losses charging options in the Consultation. ESBPG does not believe that any of these options for reform to the Losses charging regime appropriately meet the primary objectives set out by the RAs.

- Three options represent opposing extremes of locational pricing approach:
    - Two options are locational charging options which do not appear to substantially address the key features identified above – we do not believe zonalisation can suitably balance cost reflectivity and stability of charges - and thus the issues/concerns raised previously by all generators.
    - One of these represents a postage stamp approach. ESBPG understands the merits of the simplicity of approach (in particular the ease with which symmetrical treatment of generation and demand could be adopted) and equally recognises it meets many but not all of the primary objectives.. Indeed ESBPG note the RAs appear to dismiss this as an option, stating "A uniform loss adjustment approach would not be compatible with the June 2005 SEM High-Level Design."
    - In the absence of agreement on a fully postalised losses regime, ESBPG note that a number of enhancements can be made to the current regime to better meet the objectives of the regime and are incremental by nature and easily implemented. These are presented our response.
- The final option reflects a TSO led approach (via purchasing of losses) which the RAs appears to dismiss as unworkable in the SEM but which ESBPG believes could have merits and could be designed to be workable.

ESBPG recognises that the application of locational signals to both Losses and TUoS is intended to improve the efficiency of the market arrangements and the efficient use of assets through the delivery of signals regarding optimal locations for the siting of power stations (locational incentives for demand have, thus far, not been considered for the island). As such both mechanisms form part of a locational signal continuum, with Losses at the short-term end and seeking to optimise real-time dispatch processes, while TUoS charges are at the longer-term end, signalling entry/exit. However, in ESBPG's view the current structure of the Losses regime fails to provide both an appropriate continuum of short term signals with long term signals via TUoS, and an appropriate mechanism for delivering an efficient energy market.

ESBPG's preference for addressing the failings of the current Losses charging regime is to apply a postalised approach. This is on the basis it most easily and pragmatically addresses the key inconsistencies and flaws of the current regime and particularly the general concern regarding volatility and unpredictability and is easy to implement.

However, ESBPG notes the clear statement made by the RAs that in their view "A uniform loss adjustment approach would not be compatible with the June 2005 SEM High-Level Design." This suggests that the RAs are not in favour of introduction of a postalised approach to Losses charging and may continue to pursue a locational approach. Consequently in responding to this consultation ESBPG has taken account of the likelihood that the RAs may seek to retain a locational element. Thus in this context ESBPG has sought in this consultation response to (i) identify and present the most important problems which need to be addressed in the treatment of Losses charges, (ii) highlight key design features of Losses charging which should be incorporated into any locational component of Losses charging; and (iii) provide for consideration an example of an alternative model of Losses charging.

Signal Consistency

Given the linkage between Losses and TUoS as described above, it is important to have consistency in the signals provided through the two mechanisms. Furthermore generators that respond to the signals provided should not subsequently find themselves in a position of being disadvantaged by shortcomings in the signalling systems. In simple terms, if the purpose is to provide locational signals so as to improve market efficiency, then generators that respond to such signals should expect to benefit (or at least not be penalised) from providing that improvement in efficiency. This is not the case in the current regime and instead generators are disadvantaged as a result of responding to the provided signals, this suggests that the signalling mechanism is flawed.

ESBPG recognises that the decision to locate a new power station at a particular location will itself influence the future operation of the transmission system and associated costs (both from an investment perspective and a losses perspective). Thus it is to be expected that any such locational decision will feed through to changes in the signals provided for that particular location. However, ESBPG argues that the charging mechanism should capture the intention of the signal it provides and allow generators to derive some benefit from responding to the signal.

Signal Stability

There is no doubt that incorporating nodal based loss factors within the dispatch process will lead to a more efficient short-term outcome than not reflecting the impact of such losses in the process, subject to the methodology utilised to determine such loss factors being robust. Enabling the dispatch process to account for the impact of the location of energy production on system losses will facilitate the delivery of a lower cost solution.

Similarly allowing the costs of network investment to fall upon those who create the need for such investment will, over time, allow for improved efficiency in the utilisation of network assets.

However, loss factors are currently evaluated annually and reflect the expected demand and generation pattern for the coming 12 month period and may, therefore, be subject to considerable difference between forecast and outturn; e.g. due to demand forecast error, as well as the use of simplified assumptions on generation patterns, interconnector flows and outage patterns. Furthermore there is considerable year on year and within year volatility. This is clearly evident from published TLAFs for 2008 and 2009 and indicative TLAFs for 2011.

Thus, any generator which responds to such a locational signal and elects to build a new plant in a location with a favourable loss factor is exposed to the risk of that loss factor changing (as a result of that generators' investment or another generators' investment at the same location) to a less favourable value both across years and within years. The impact of a reduction in the applicable TLAF is significant for a plant. This impact arises not only in relation to a general reduction in a plant's revenue resulting from the devaluing of the energy provided by the plant (as a result of the losses incurred on the system), and a similar reduction in capacity payment, but also as a result of the loss factor being reflected within the dispatch process, reducing the running regime for the plant in comparison to that assumed based on the original (pre-construction) loss factor and incurring both reduced turnover and increased operational costs.

Fluctuations of this magnitude will make project financing more difficult, increasing the costs faced by new investors and, therefore, electricity consumers as these costs will be reflected through generators' bid prices. This level of year on year volatility is not acceptable for a new entrant plant; and can potentially completely destroy the project economics.

Furthermore any substantive reduction of output from the most efficient new entrant plant provides material inefficiencies to the energy market and thus costs in both consumer price and environmental terms; which far outweigh the materiality of any losses benefits.

Inefficient use of the most efficient generation will also impact unfavourably on the environment via increased emissions to atmosphere. ESBPG contends that this is not the intention of the locational signals, nor is it consistent with the objective of delivering efficiency in the use of the network.

Investment Finance

Any TUoS and Losses charging regime needs to specifically take into account the requirement to make the Irish market an attractive location for generators to invest.

Traditional-style, non-recourse project financing for independent generation projects has been a cornerstone in the development of new generation capacity in economies such as the U.S., the U.K., mainland Europe and also in less-developed countries. This form of stand-alone financing effectively allows companies in the generation sector to develop more projects than their own balance sheet capacity can itself support. Putting successful project financing in place for electricity generation projects in any market depends, among other things, on the stability of the regulatory / market regime that is in place and the associated stability of earnings and debt servicing capability.

A TUoS and Losses charging regime for the island of Ireland that imposes unpredictability and volatility, raising project costs and increasing project risks, will make Ireland off-limits to project finance for power generation projects. As project financing is a very specialised form of finance only engaged in by some banks who typically participate again and again in syndicates on each project, the word will quickly spread that the Irish market regime is unacceptable for project financing. Few, possibly even no, generation projects will secure project finance in this market.

Inability to secure project financing for Irish generation projects will very quickly lead to re-assessment of the viability of corporate lending for power generators in this market also. Perceived high business risk will undoubtedly lead to a lesser appetite for lending to this sector, particularly against a background where the credit crunch and collapse of bank balance sheets has already led to much lower levels of lending that at any time in the last 10 years. This will also serve to curtail the development of the power generation sector.

Ireland is effectively competing for the international pool of finance, whether through project finance debt or corporate lending, that is available for the power generation sector. A TUoS and Losses charging regime that unreasonably increases the risk of project viability will deter lenders and investors from the Irish market.

Reflecting Through the Locational Signal

ESBPG suggests that a reasonable outcome of the application of a locational signal would be for any generator which responded to such a signal to derive a benefit in recognition of the assistance it is providing to the system as a whole. Furthermore any such signal should display a degree of consistency year on year so as to provide for a degree of stability. This is not to say that the signals should be damped such that the efficiency derived through the dispatch process is lost, but rather an approach should be developed which reduces the impact.

In principle one way of ameliorating the dynamic impact of nodal loss factors is to smear the impact across zones. By grouping nodes together and determining a loss factor which reflects the combined impact of the grouped nodes it is likely that year on year volatility will be reduced (effectively by averaging the nodal contributions). However a mechanism for determining the right grouping of nodes is not easily established and to some extent the drawing of the boundaries is likely to be (in part) arbitrary. The creation of the zones for the purposes of the application of Transmission Network Use of System (TNUoS) charges in GB was based upon pre-existing zonal definitions employed by National Grid. Although they are derived under three objectives (geographic contiguity, zonal charge stability and reasonable closeness of nodal costs within a zone) deriving zones has been more of an art than a science. As such the definition of zones has been a constant difficulty within GB transmission charging and subject to much debate and contention by the industry.

No such zonal groupings exist for the island of Ireland. The same issues of how to appropriately define zones would arise as experienced in GB for example and in ESBPGs view establishing robustly determined criteria for their creation would prove difficult, if not impossible. Furthermore, while such an approach would damp the year on year volatility to a degree, in order to do so to the extent necessary to address generator concerns regarding volatility – without changing any other feature of the Losses charging regime (as intimated in Losses Option 2) - the zones would need to be so large that this would also compromise dispatch efficiency.

Furthermore, simply using zones to address volatility ignores the major flaws in the Losses charging structure and underlying TLAF calculation methodology. As such it is a sticking plaster solution which does not properly address the core issues driving the need for reform. These substantive areas for reform are addressed by ESBPG later in this response where it identifies three key features which should be addressed and present within any future Losses charging regime and two further potential features which could provide additional benefits to new entrants and the market as a whole.

Signal Methodology

The current TLAF calculation methodology is based on the incremental marginal cost of further additional generation at a particular location. As demonstrated by analysis conducted by the GB electricity industry within its own consideration of locational losses charging, this dramatically overstates the impact of generation at a particular location on the transmission losses as

(i) it fails to recognise the relative impact of the generation at that site at lower levels of output

(ii) it fails to consider the interaction with other generators' behaviour and output patterns

It is clear that a generator operating at less than full load has less impact on transmission losses than where it is operating at full or "full plus incremental" load. Analysis conducted within the GB market has suggested that purely incremental marginal cost based TLAFs overstate actual transmission losses impacts by up to a factor of 2. This is clearly very substantial and directly leads to inefficient dispatch of generation by overstating their relative TLAFs and thus unduly distorting comparative generation economics. In essence, the current TLAF methodology calculates an incremental marginal MW cost based tariff and applies it on all MW, i.e. as if all MW have the same impact from zero to full load (plus increment). In addition to substantially exaggerating/overstating the impact of generation at a site, this methodology is clearly internally inconsistent and incorrect. It is further noted that by unduly impacting on more efficient and greener generation this has an adverse impact on the costs and environmental impact of generation as seen by consumers.

ESBPG notes that in their paper setting out the assumptions employed in preparing the indicative TLAFs for 2011 ("*2011 TLAF Assumptions", November 2008*) the System Operators highlight that "*the distribution of wind generation on the system can have a significant impact on the way transmission losses are distributed*". This is clear given that the intermittency of wind is likely to correlate locationally. However the same document notes that wind generation was modelled as a flat profile at a 32% load factor and that this was the same approach as was adopted for the derivation of the TLAFs for 2009. As the quantity of wind capacity on the island of Ireland is set to grow significantly in the coming years in order to help the Government meet its greenhouse gas reduction and renewable energy targets, ESBPG question the validity of the approach adopted to the modelling of wind generation in determining TLAFs. The variability of wind generation is significantly greater than that of conventional plant, and in particular when compared to base load plant which in turn is most significantly adversely affected by the application of TLAFs. Given the long-term nature of generation and transmission investment decisions, whatever mechanism emerges as a result of this review must be future proof, at least for known significant events such as the envisaged proliferation of wind energy on the island. In ESBPG's view, modelling wind generation as a flat profile will not adequately reflect the impact such generation has upon the distribution of losses and an alternative process should be found which better takes into account the natural stochasticity of wind output and the greater variation in generation patterns likely to be seen over the course of year as the levels of intermittent generation grow substantially as expected.

Cost Sharing with the TSOs

A further point to consider is the influence the TSOs are able to have on system losses. Once a power station is built and a load centre has connected to the Transmission System, transmission system losses are outside the control of either the generator or the demand side. The TSO on the other hand is in a position to influence losses both in its operation of the system (e.g. dispatch), the decisions it makes in terms of the need for network investment and the equipment it purchases to undertake such network investment. It therefore seems reasonable that some of the cost of Losses should also be borne by the TSOs, most especially in respect of the non-variable element of system losses.

The consultation paper stipulates that implementation of a mechanism whereby the TSO purchases Losses would need significant infrastructure investment and would not be considered compatible with the SEM. As the consultation does not elaborate on these points ESBPG assumes that:

- These onerous infrastructural requirements arise from the lack of metering at the Transmission/Distribution boundary – such metering being required to quantify the actual losses to be purchased by the TSO; and

- The lack of compatibility with the SEM arises from the lack of a locational signal in the allocation of Losses.

ESBPG consider that both of these issues can be solved as follows.

It would be possible to estimate the cost of Losses by running an unconstrained schedule with and without TLAFs and to allocate this cost to the TSOs. This would avoid the need for metering at the Transmission/Distribution boundary.

Furthermore it may be possible to use this approach to split the cost of losses between generators, demand, and the TSOs by adjusting the TLAFs in the estimation process, and thereby, if it is considered desirable, to retain an element of locational costing directly upon generators and demand. This mechanism would be based on estimation rather than true identification of the cost of Losses. However this is also true of the current methodology.

Key Features that any new Losses Regime should include

ESBPG strongly favours a postalised charging regime, for the reasons stated above. However in the event that a locational element is retained, ESBPG believes the current Losses charging regime is in need of substantial reform, and that the options currently identified do not capture the full range of possible charging regime structures. As such ESBPG has identified 3 high-level features which it believes must be taken into account, in order to better meet the primary objectives as set out in the Consultation in a balanced manner and which should form the basis of <u>any</u> future Losses charging regime. These are:

1. sharing of cost of transmission losses between generation and demand;
2. recognition of fixed and variable losses within the charging structure;
3. more cost reflective TLAF differentials, without the distorting (and magnifying) effect resulting from the incremental marginal cost approach.

None of the 4 options identified in the consultation contains these features. ESBPG believes that these 3 key features should be embodied within any future Losses charging regime, for the reasons set out in the following sections.

Sharing of costs between generation and demand

Transmission losses are driven by combined siting and operational behaviour of generation and demand, rather than of generation alone. Thus it seems inequitable that the full cost of losses is borne by generators, especially through a fully locational Losses charging regime.

Furthermore the RAs have explicitly identified as one of their primary objectives in section 3 of the Consultation document that it is important to ensure consistent treatment of generation and demand within charging regimes (both for TUoS and Losses). Given this objective and the shared responsibility for network losses, we believe it reasonable to expect the total cost of losses to be borne equally by generation and demand.

Thus, ESBPG proposes the total costs associated with losses should be equally recovered from generation and demand, i.e. 50/50. This will not impact on the overall price for consumers – indeed the explicit cost will further incentivise energy efficiency and could materially reduce costs.

In principle we believe that the Losses charging structure for demand should mimic that for generation – essentially being equal and opposite on the basis that generation = "negative demand". However, in the context of locational based Losses charging we recognise the lower elasticity of demand siting response and wider political imperatives such as the need to stimulate the economy across Ireland on a planned and equitable basis, rather than driven by transmission network considerations. Consequently, ESBPG believes it is both pragmatic and reasonable to apply Losses charging to demand on a postalised basis.

Recognition that losses consist of fixed and variable elements

Transmission losses consist of fixed elements (such as corona losses) and more variable elements (such as circuit losses). This is a well understood feature of electrical systems; and indeed some TSOs report losses in a disaggregated fashion e.g. National Grid under Table 7.4 of the GB Seven Year Statement indicates the components of overall transmission losses at time of peak demand – which consist of fixed (e.g. corona losses), semi-variable (GSP transformer losses) and variable components (circuit losses).

The fixed elements are not driven by generation (or demand) siting decisions or by generation (or demand) operational behaviour but rather reflect the nature of the transmission network itself. Dependent on the duration and timing of the period over which transmission losses are measured and prevailing generation patterns and network availability within this period, ESBPG believes fixed losses can be 20%-35% of total losses for a given time period.

Furthermore, in reality, variable elements will also have a de minimis level below which they will not fall. For example, heating losses due to transformers at all Bulk Supply Points will always be present to a degree i.e. there will always be a number of BSP transformers taking power. There is variation depending on the number and size of BSP transformers in use and their level of utilisation at any point in time and over a period of time; but in practice this is likely to be relatively limited. ESBPG believes the de minimis level of variable losses can represent 5-15% even under extremely favourable generation dispatch assumptions; and is probably more likely to be 15-30% under more central assumptions. This represents a further “quasi-fixed” element of the transmission losses.

At present, by simply applying a purely locational Losses charge, the current Losses charging regime does not recognise the physical reality of how transmission losses arise and the degree to which they are attributable to generation (as discussed above) and locational factors. As such the current locational transmission charge is not cost reflective, which is one of the RAs stated primary objectives in section 3 of the Consultation document.

ESBPG proposes that any future Losses charging mechanism should recognise this physical reality and even in the event that a locational element is retained, it should apply to the variable component of transmission losses only. The fixed component (35%-65%, the exact figure to be based on analysis and evidence from the TSO) of the costs recovered from generators should be levied on a socialised €/MWh basis

As indicated, we are happy to be advised by the TSO based on its own network modelling and understanding of transmission losses on what the appropriate demarcation/definitions of “fixed” losses and “variable” losses are and on this basis what is an appropriate percentage of overall losses to allocate to each of fixed and variable losses components

More truly cost reflective TLAF calculation

ESBPG believes there are number of substantial problems with the current TLAF calculation methodology, as follows:

- ESBPG strongly believes a pure (incremental) marginal cost based TLAF calculation methodology overstates the impact of generation (and demand) location and behaviour and thus TLAF differentials. Essentially a marginal MW cost based tariff is applied on an average basis to all MW – this is clearly inconsistent and incorrect. We believe this is further evident from the required adjustment to TLAFs under the current regime; and the consequence of overstated TLAF differentials is inefficient dispatch.

- The current TLAF calculation methodology does not reflect the impact of highly varying generation patterns which arise from intermittent generation. This variation in intermittent generation output can have a strong influence on losses and this is an issue which will rise in significance over time.

- Furthermore we believe the current TLAF calculation methodology fundamentally creates the high level of volatility and unpredictability which is of such concern to the generation community as a whole.

- Finally we note the inconsistency of TLAF calculation with the SEM design. Currently TLAFs are calculated on a Day/Night basis, whereas generators are required to submit their P/Q pairs on a daily basis. Consequently there is a misalignment. Which the generators have to try to manage in their bid submissions. To try to do this requires an element of judgement and ex-ante expectation of dispatch which is likely to be incorrect to a greater or lesser degree.

In the context of the above, we believe the current TLAF calculation methodology is not consistent with four of the RAs primary objectives stated in section 3 of the Consultation document i.e. it is not cost reflective, is volatile, is unpredictable and leads to inefficient short term dispatch.

We understand there has been substantial analysis conducted on locational TLAFs in GB given long running review of the form of charging for transmission losses under NETA and now BETTA. We further understand that analysis conducted by the industry in GB suggests that pure incremental marginal cost based approaches can overstate the impact of generation location on losses by an order of magnitude. Consequently, we believe that the TLAF calculation methodology must seek to better reflect the average impact of generation and demand patterns and their variability over time; as well as meaningfully addressing the issues of charge stability and predictability.

In the event that loss charging retains a locational component, ESBPG believes that there should be a more sophisticated calculation of TLAF. Although simple aggregation of nodal TLAFs into zones under the current TLAF calculation methodology may dampen volatility to a small degree, it will not address the key issue of overstating the TLAF differentials in the first place. Thus there needs to be a more substantive adjustment to the TLAF calculation methodology.

ESBPG anticipates there are a number of different potential approaches which will have either been applied in other markets where locational loss factors are applied or within relevant academic circles looking at how to deliver efficient energy markets. We have not had the opportunity to explore these but would hope the RAs and its advisors would be able to do so within the Consultation exercise.

At a high level ESPBG believes that any TLAF calculation methodology should seek to derive an "average" locational TLAF for a given connection point rather than an “incremental” marginal locational TLAF. This should reflect the differing generation levels from locations rather than simply assuming the maximum existing connected generation plus an increment.

Furthermore, ESBPG believes that given increasingly variable generation patterns it is important to consider the impact of these on TLAFs (e.g. via stochastic modelling). ESBPG believes that this is necessary to better capture forward uncertainty for the year ahead and will give a better idea of more typical TLAFs during the course of the year. This should be possible without creating unduly volatile and unpredictable Losses charges.

ESBPG recognises the demand for transparency and thus the need to avoid creating an excessively complex charging structure in an attempt to achieve cost reflectivity. Consequently, a simple fix/adjustment to TLAF calculation would be to adjust the marginal TLAFs multiplicatively to recover the real cost of losses rather than the universal subtraction of a constant as at present. This has the merits of simplicity (and thus ease of implementation) and is likely to lead to more cost reflective TLAF differentials.

To strike an appropriate balance between simplicity and cost reflectivity ESBPG’s proposed approach to calculation of any locational component of TLAFs seeks to be pragmatic; i.e. we propose that the TSO conducts modelling to derive a relationship/ratio between the locational marginal cost of losses and the locational average cost of losses, for each node and use this ratio to reduce marginal TLAF differentials (by multiplying the ratio against each marginal TLAF). Any residual over/under recovery could be addressed by a subtractive/additive vertical adjustment as now.

Potential alternative Losses charging model which could be considered

ESBPG has previously highlighted its view that Losses Option 4 in the Consultation document could be made to be workable. In this section we outline our concept for how it might be usefully applied and can also facilitate potential TSO incentives.

We started our thinking for this alternative model from the basis that the current arrangements do not recognise that the TSO can have an impact on losses on their network (whether this is fixed losses not influenced by generation or demand or variable losses) via both investment and operational actions (efficiency of which are two of the primary objectives highlighted by the RAs in the Consultation document).

Whilst ESBPG recognise that the SEM design may limit the ability of the TSO to take dispatch actions which help to reduce losses there are possibilities via outage management for example; and it may be possible to adjust dispatch process to expand their ability to do so cost reflectively in a way which improves the overall efficiency of short term dispatch. ESBPG also believes it is appropriate to provide the TSO with cost benefit signals regarding the nature of its network investment and its impact on losses in the long term.

TSO incentives can be fitted to any Losses charging regime but is perhaps most easily fitted to a regime where the TSO purchases Losses in the first instance and then seeks revenue recovery from market participants.

One such possible model would work as follows:

(i) The TSO would purchase all Losses in the first instance.

(ii) Generators would submit bids to the SEM excluding any adjustment for losses.

(iii) The TSO would undertake the Unconstrained dispatch run on the basis of these bids.

(iv) The TSO would undertake the Constrained dispatch run on the basis of these bids with application of appropriate TLAFs; and dispatch accordingly – thus including losses within overall optimisation of dispatch.

(v) 50% of the cost of losses would be recovered on a socialised basis from demand.

(vi) 35%-65% (to be determined as appropriately cost reflective of “fixed” losses) of the cost of losses to be recovered from generators would be recovered on a socialised basis via a €/MWh charge on output.

(vii) The remaining 35%-65% (reflecting “variable” losses) would be recovered via an “average” nodal locational TLAF for each generator.

(viii) Recognising the metering issue ESBPG proposes that in the interim period before comprehensive metering has been installed – and perhaps on an enduring basis if an ex-ante approach is preferred - that the total cost of Losses is estimated ex-ante as now; to enable ex-ante revenue allocation and charging.

(ix) Furthermore recognising the importance of ex ante signals and transparency for generators, ESBPG proposes that the average locational TLAFs are calculated ex ante as now.

(x) Any residual under/over recoveries arising due to the ex-ante approach could be recycled into the following year's socialised charges subject to (i) any desired re-openers where the residual is deemed to be excessively large; and (ii) any desired incentives rewarding/penalising the TSO for good/poor performance, including in relation to network investment to reduce losses in the long term.

Whilst the detail of the above alternative model could be refined ESBPG believes it forms the basis of a credible option for consideration when assessed against the primary objectives outlined in the Consultation document and taking into account wider considerations of practicality and energy policy. As such ESBPG believes it is worthy of discussion within the industry debate on the appropriate form of Losses charging going forward. The key point is that ESBPG does not believe that the current 4 options as put forward in the Consultation document represent all potential viable options which could be considered, nor address some of the key concerns of the generator community.

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