Response from AES to

Draft Transmission Loss adjustment Factors for 2009

SEM-08-121

10th October 2008

Introduction

1. AES welcomes the opportunity to respond to this consultation. The objective of locational charging for transmission losses is to encourage generators to locate close to demand. Belfast is the second largest demand centre on the island and Kilroot is the closest generating station to Belfast. Kilroot and Belfast are connected by a very strong 275 KV network with surplus capacity. If the objective of locational charging is being achieved, one would expect Kilroot to have a relatively competitive TLAF. However Kilroot's average proposed TLAF for 2009 is 0.977, versus an average TLAF of 1.008 for all nodes in the RoI and 0.982 in NI[1]. This result is counter intuitive and merits closer examination.

2. The distribution of TLAFs among generators has a material impact on relative competitiveness. The comments by the RAs on page A7 of the decision paper "*Treatment of Transmission Losses*" in August 2006, suggests that they see this as the most important consideration:

   > *"Finally, in an all-island market, the RAs consider that the competitive position of generators relative to each other across the whole island is the most important consideration".*

   We note however that the RAs make no reference to locational charging across demand, notwithstanding their statutory duty to also promote competition in supply.

3. It is important to remember that even a one percent difference in TLAFs will have a material impact on relative competitiveness. A useful comparator would be the impact of a one percent improvement in a generating unit's heat rate. Over the lifetime of the project, this amounts to millions of euros.

4. The RAs have a statutory duty not to discriminate unfairly between licence holders. Given that TLAFs are not based on actual metered data, it is very important that the methodology employed to estimate and apply TLAFs is robust and fair.

5. The 2005 consultation paper on the SEM High Level Design appears to identify three key objectives in regard to the treatment of transmission losses:

   - Minimising losses via the dispatch process (dynamic efficiency),
   - Correct allocation of the cost of losses in the settlement process, and
   - Provision of locational signaling for new entry and exits.

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[1] These averages are calculated from the excel sheet data provided with the consultation and include TLAFs for all nodes.

The question of how to calculate the loss factors was also considered; should they be calculated dynamically in every trading period or should they be calculated using static loss factors calculated on an annual basis and applied to the entire volume produced by each generator? It was proposed (and later decided) to use static factors as this was the present practice for reasons of simplicity and ease of implementation. The RAs stated:

> *"It is proposed that static rather than dynamic loss factors are used in the SEM* *initially* *as is the present practice in both jurisdictions for reasons of simplicity and ease of implementation".* (Emphasis added)

6. Furthermore, in the consultation paper in May 2006 on The Treatment of Transmission Losses the RAs stated that :

> "*Adopting this approach will maximise the re-use of existing systems and procedures, minimizing costs and risks to SEM implementation, and result in treatment that is familiar to users in one of the two jurisdictions".*

Whilst we recognise the need to begin with some approach, we would respectively comment that the reasons given above have limited economic foundation, when measured against the objective criteria set out in paragraph 4 above. However the RAs went on to say that:

> *"Notwithstanding the above, the RAs acknowledge that ESBNG has, at all times, been considering how the derivation of TLAFs might be improved, and that this provision would have continued without the introduction of the SEM. It is appropriate that any such improvements still be considered, should the methodology currently used by ESBNG be adopted for the SEM".*

The positive implication here is that the RAs remain open to suggested improvements or alternative approaches. In complex areas of this nature, this is clearly sensible.

7. The TLAFs applied for 2008 and proposed for 2009 vary materially across competing generators. In light of these results AES has reviewed the methodology employed in the SEM against the criteria set out in paragraph 4 above. We have uncovered what we consider to be material flaws in the derivation and application of loss factors, and in the subsequent allocation of costs.

8. The next sections of this paper examines how TLAFs are derived and applied and how resulting costs are allocated. Improvements are also suggested. The paper

then provides a brief literature review on the subject and ends with conclusions and recommendations.

Derivation of TLAFs

9. Our understanding of the steps to derive TLAFs is as follows:

    - Power flow studies are carried out to forecast the total transmission system losses.
    - Twenty-four "base case" dispatch scenarios are established (12 months, day and night) in which the output of each generator is set at a specified level.
    - For each base case, the total system demand is increased by 5 MWs, on a pro-rata basis across all demand nodes. This incremental demand is met by only the generator being studied (the "swing bus"). This is repeated for all generators dispatched in the base case.
    - A Marginal Load Factor (MLF) is derived for each generator as delta Demand divided by delta Export Power.
    - The process is then repeated by reducing demand by 5MWs and another set of MLFs are derived. An average MLF is then calculated for each generator.
    - Each MLF is then multiplied by the maximum dispatch volume for each generator. This results in over-recovery (because marginal losses are higher than base case losses). Scaling of the MLFs to meet the base case losses is performed using a "shift method" (subtractive or additive).
    - The base case losses are then multiplied by the number of hours in each seasonal scenario and summed to find annual losses. This total value is then compared to the forecast value for the year to determine what further adjustments are needed.

Commentary on the Above Approach:

10. The full marginal loss factors are linearly scaled across all dispatch volumes. This introduces a major flaw because (i) there is a convex relationship between transmission losses and power flows; transmission losses are approximately proportional to the square of the power flow[2], and (ii) variable transmission losses vary with distance of travel along lines. Clearly therefore, the variable transmission losses arising from a generating unit at half load, for example, are

[2] Average losses from a generating unit are considered to be about half of marginal losses.

much less than 50% of the full load losses. Furthermore, the distance of travel will be different for each block of load, also resulting in as non-linear relationship between load and losses. In other words, the most efficient blocks of generation in a particular region can meet local demand. It is only the less efficient marginal generation than may need to be exported to other regions[3]. The proper approach therefore would be to gradually populate the transmission network with blocks of generation (starting with the most efficient) and demand and derive loss factors for each block in turn. This is consistent with the existing approach of generators declaring different price/quantity pairs for dispatch in the energy market. In effect each generator would end up with a TLAF curve.

11. The proposed TLAFs for NI generators are materially less than the average for RoI generators. This outcome is hardly surprising given the marginal flow methodology employed. If the all-island network is already populated and demand is then increased pro-rata across all demand nodes on the island by 5 MWs, electrons from NI will have further to travel on average than those in the RoI because the cumulative incremental demand will be higher in the RoI. This outcome will happen no matter what the supply/demand balance is in either region. The approach is clearly flawed.

12. If we are to achieve economic efficiency in dispatch, variable transmission costs should be optimised in one step with all other variable costs, across all P/Q pairs. However the approach adopted here does this in two steps. As a first step, base case dispatch scenarios are assumed in the absence of transmission losses. These are then used to model full marginal transmission losses. However if all variables were modeled in one step, the dispatch outcome is likely to be different.

13. The approach is not measuring actual losses for each generator in real time. It is very much a static approach based on a number of assumed dispatch scenarios. Actual dispatch in real time will be different from that modeled. It is worth noting that, in the proposal for BETTA, real data from the previous year is used to estimate TLAFs for the current year.

14. For this consultation we were only provided with what appears to be the resulting generation outputs and demand for one scenario (this may be an average of all scenarios?). It is difficult to give a fully intelligent response because the input assumptions used for each of the scenarios are not provided. These assumptions would include demand, availability, fuel prices, transmission constraints, operating reserve, wind, and even TLAFs! The latter assumption introduces a circularity issue and we assume that the model assumes that the TLAFs are all one.

[3] This goes to the point about Kilroot being the closest plant to Belfast.

Application of TLAFs in the SEM.

15. The first objective in paragraph 4 above was to minimise losses via the dispatch process. The SEM dispatches generators in price/quantity pairs. Each price is meant to represent the total variable cost for that quantity of output. As explained above however the methodology presently used in the SEM applies the marginal loss factor to all volumes, not just the marginal volumes. However losses vary across dispatch loads as the transmission system is populated. Therefore to apply a marginal loss factor to all dispatch volumes will result in inefficient dispatch or sub-optimal allocation of resources.

16. Interestingly however the SEM dispatch engine ignores TLAFs. This suggests that, for dynamic efficiency to prevail, generators would need to include TLAFs in each of their P/Q pairs. However the TSC required generators to submit P/Q pairs based on the quantities delivered at the station gate, not at the trading point (which is the notional exit point from the transmission network). At the station gate, no transmission losses have yet occurred. This therefore would suggest that generators must exclude TLAFs from bids.

17. It is far from clear if and how generators are actually including TLAFs in bids. The consultation and decision papers on Bidding Principles do not give any guidance on this point. If generators should be including TLAFs in their bids, how should these be factored in? As described above, the actual transmission loss is different for each load block, but the generator does not have this information. All they have is the MLF but this is only appropriate for its marginal generation, and then only under certain dispatch scenarios. Furthermore, the generator itself does not incur the physical transmission loss. Commercially in settlement (see below) the quantity paid at SMP is adjusted by the TLAF and it is this loss (or gain) of revenue which the generator incurs. Should a prediction of this value therefore be included in bids?

18. Taking the last two points together suggests that TLAFs may not be used at all in determining dispatch. If this is the case, then the objective of achieving dynamic economic efficiency and optimal allocation of resources is completely defeated.

19. Another objective in paragraph 4 was to provide a locational signal for new generation. The signal from historic or present TLAFs is inappropriate. A potential investor needs to be able to model expected future TLAFs over the lifetime of an investment. However these values are not available and in any case would be very difficult to predict. In a small system like the SEM, future TLAFs will change materially with plant entry or exit, and with development of the network. All of these influences are outside the control of an individual investor. This volatility and uncertainty will result in an increased cost of capital.

Allocation of Costs

20. Transmission losses are both fixed and variable; for BETTA the split is assumed to be 50:50. Presently however in the SEM **all** transmission costs are allocated on a locational basis across generators. This is clearly inefficient and unfair. Correction would narrow the range of TLAFs between generators. By comparison, in the system proposed for BETTA[4]; 50% of the costs are charged on a locational basis and the other 50% are postalised.

21. Losses on a transmission system are influenced by the location of both generators and demand. They are also influenced by the operation, maintenance and development of the transmission network. Presently however in the SEM costs are allocated 100% to generators. This would appear to be at odds with the objectives in paragraph 4. The interest of customers is best facilitated by cost-reflective charging arrangements that promote the efficient and lowest cost development of the network and by effective competition between generators and suppliers which drive down prices. Clearly if demand users of the network had to contribute to the cost of losses this would incentivise them, all else being equal, to locate where charges for losses are least. This point does not appear to have been consulted on previously.

22. In the system proposed for BETTA 55% of transmission losses are allocated to demand and 45% to generation[5].

Literature Review

23. To help inform our response and to hopefully provide some helpful suggestions, AES conducted a limited literature review on this subject. We reviewed two papers; one by Janusz Bialek and another by J. W. Bialek and P.A. Kattuman[6]. Below, these papers are referenced as Bialek and Kattuman et al respectively.

24. Kattuman et al claims that:

> *"Application of marginal pricing for transmission loss charging encounters a number of possible problems which are especially pronounced when developing a common transmission framework for an interconnected system."*

The first problem they identify is a lack of transparency and difficulties verifying charges, leading to suspicion from market participants. Secondly the marginal

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[4] See "Zonal Transmission Losses – the Authority's minded-to decisions, Ofgem website, 26th June 2007, page 2.

[5] See "Zonal Transmission Losses – the Authority's minded-to decisions, Ofgem website, 26th June 2007, page 5.

[6] "*Proportional Sharing Assumption in Tracing Methodology*", J.W. Bialek and P.A. Kattuman, July 2004 and "*Topological Generation and Load Distribution Factors for Supplemental Charge Allocation in Transmission Open Access*", Janusz Bialek, August 1997.

loss factors are volatile increasing the cost of capital. Finally Kattuman et al identify the scaling problem when we try to scale marginal losses across the entire power flow from a generator because losses are proportional to the square of this power flow and the distance of travel along the line (which also varies with output).

25. Kattuman et al propose an alternative to the marginal pricing methodology for allocating transmission losses. This is referred to as the *tracing methodology* and is based on the assumption that, at any network node, the incoming flows are proportionally distributed among the outcoming flows.

26. Referring to the marginal cost approach, Bialek states that:

> *"It has been found, however, that the marginal pricing of transmission services is highly volatile, provides preserve economic signals to the transmission company, and fails to recover the total incurred network costs"*

27. Bialek goes on to describe the MW-mile methodology to conceptually determine "generalised" distribution factors for power flows. The approach typically results in *counterflows* or negative charges. Bialek claims that transmission service providers may feel uneasy about the idea of providing a service and paying the customer who uses it. We too feel uneasy. In the existing SEM application, payments to generators with TLAFs greater than one appear to come from generators with TLAFs less than one. If marginal loss factors are applied to all volumes, which is the current SEM practice, this impact is magnified.

28. Bialek proposes a novel, topological approach to MW-Mile charging which determines the *share*, as opposed to the marginal *impact*, of a particular generator or a load in every line flow. This appears to be very similar to the tracing methodology. The physical meaning of topological factors is obvious as they represent a positive share of a particular generator/load in the line flow.

29. Both approaches result in positive contributions from all network users to the cost of losses, hence rescinding the problem with counterflows that results from a Mw-mile and marginal loss approach.

Conclusions

30. TLAFS have a material impact on the relative competitiveness of generators. Given that losses are not metered, it is vital that the derivation of TLAFs from modeling and their application is robust and fair. AES is firmly of the view that this is presently not the case.

31. We now have two years of data for proposed transmission losses determined by an ex-ante marginal loss methodology. This data demonstrates a material

variance in TLAFs between regions. Whilst this variation might be understandable for marginal flows, given the distribution of demand and generation nodes, it is unrepresentative of losses across all generation volumes.

32. Linearly scaling of marginal loss factors across all volumes materially misrepresents actual losses. The approach is economically inefficient and unfair. It is also inconsistent with the treatment of all other variable costs in the SEM; variable costs are identified and bid in blocks.

33. The marginal loss factor approach also suffers form being opaque and volatile leading to discontent and suspicion amongst market participants.

34. The market operator does not include TLAFs in the dispatch algorithm and its unlikely that they are properly included in generator bids either, if at all. This suggests that dynamic economic efficiency is not being achieved.

35. It is economically inefficient and unfair to (i) allocate fixed transmission losses across generation on a locational basis and (ii) to exclude demand from the allocation of variable transmission losses (on a locational basis).

36. In a small system, current or historic TLAFs are unrepresentative of likely future TLAFs. Future entries and exits together with changes to the transmission network will have a major impact on future TLAFs. However these events are largely outside the control of an investor in an individual generating plant. The resulting volatility and uncertainty will result in an increased cost of capital. When one combines this with the question marks surrounding the derivation and application of TLAFs in the first place, it is debatable weather net savings will actually be achieved with the introduction of locational TLAFs.

Recommendations.

37. The SEMC should commission an independent review of the application of TLAFs in the SEM. This review should include a literature review together with applications in other markets. The potential options for the SEM should then be examined and consulted on.

38. In the interests of fairness, until this review is complete and a more robust analysis provided, transmission losses should be fully postalised, with 50% allocated to generation and 50% to demand. At the very least, 50% of charges to generators should be postalised across generation output to reflect the fixed component of losses.