TUoS and TLAF charging

Further comments on the main questions raised in the Eirgrid/SONI Questionnaire

A submission by Synergen

This paper sets out Synergen comments on the existing and future TUoS and TLAF charging principles. Specifically this paper considers the appropriate basis for the harmonised charging of TUoS and TLAFs in the SEM.

1 TUoS charging

The development of the SEM (with its harmonised approach to the setting of energy prices) required that consideration was given to the appropriate allocation of charges between competing entities. As early as 2005 the High Level Design suggested that generators should pay shallow connection charges, and locational TUoS. Such arrangements were to be considered *"in parallel with the development of the detailed rules"*. The July 2006 consultation considered that the RoI EirGrid methodology broadly fulfilled these objectives. This consultation also considered the level of costs that may be recovered. In 2007 the RAs determined that the main proposals from the July consultation would be adopted. Further consultations on the detailed methodology followed in 2007, and 2008 – notably SEM-08-067 and the consequent decision paper.

1.1 The principle of harmonisation across NI / RoI

Synergen considers that it is of central importance that the generator TUoS arrangements are harmonised as a matter of principle. Synergen considers that harmonisation has been a central RA policy undertaking and should be adopted at the earliest practical opportunity. Synergen understands that generators may have made investment decisions in the knowledge or expectations of specific TUoS charging regimes. However, TUoS charging arrangements within the RoI have changed over time, as they have in other jurisdictions. As Synergen does not consider that TUoS is a major determinant of investment decisions, it is unlikely that any existing generators would have stranded investments as a consequence. Consequently, there is no rationale for not harmonising arrangements as a consequence of historic network configurations, or other jurisdictional factors.

Synergen notes that there are many other costs / prices within the SEM that could be set more efficiently on a jurisdictional basis (i.e. regional energy pricing) but have been rejected. The cross-jurisdictional nature of the SEM thus dictates that input costs for a generator are common for so long as payments are made on a common basis.

1.2 Approaches

Synergen considers that either a fully cost reflective, or an explicitly socialised / averaged (i.e. "postage stamped") TUoS charging regime could provide a valid framework for TUoS charging – noting that either of these would be on a fully harmonised basis. What would not be acceptable is (a) differential allocations of the cost base between jurisdictions, or (b) differential charging arrangements, (c) partially cost reflective charging regimes based on grandfathered rights or specific decisions to exclude some generators from the charging arrangements, or some transmission assets from the calculation of TUoS charges. In this context Synergen notes that under the SEM it sells to all retailers on a pro-rata basis under the pooling arrangements, and consequently it's deemed SEM trades are both in the RoI and NI.

The broad approaches or cost reflective charging and socialisation are discussed in turn below.

First, there can be a full, cost reflective allocation of charges for all participants on an all-island basis. This would undoubtedly lead to a re-balancing of the existing charges between the generators that already pay such charges. There would also be a need to include the increasing number of smaller generators (below the 10MW limit) into the charging regime and develop the modelling scenarios, and consider complex and potentially contentious issues such as the inclusion, or otherwise, of lightly loaded lines. In short, there could be a decision to move towards a robust, fully cost reflective, allocation of generator TUoS charges. This would be expensive, and time consuming. Synergen considers that such an approach would require a clear cost benefit assessment – it should be demonstrated that the allocation of such charges in a cost reflective manner produced either productive or allocative efficiency gains.

Second, a "postage stamped" regime could be based on a more simple set of charging principles. These may not be completely cost reflective (and thus not entirely aligned with the RAs high level decision on the market design) but may be more pragmatic and consistent with other elements of market design.

Such an approach may be appropriate if the allocation of locational TUoS costs is (a) not a significant factor in the future siting decisions of generation, (b) is not consistent with other aspects of the SEM design. These issues are discussed in turn below.

1.2.1 The role of TUoS in generation investment decision making

Synergen does not consider that new generation locational decisions are driven by locational TUoS charges. In particular, Synergen notes that:

- Long term historic locational decisions have been taken – locational charging through TUoS has no impact on existing decisions, and provides no signal an existing player can react to.

- Regarding new investment, TUoS is at best a second order determinant for a new entry's choice of location.

- The Grid 25 initiative represents an increasingly centrally planned approach to connecting new generation schemes. In this context, locational signals through TUoS for existing and new entrants appears to be an increasingly weak signal.

However, if there were to be a locational signal, the net benefit of any locational signal should be demonstrated – i.e. it should be shown that the differential allocation of costs:

- drives future locational decisions; and

- reflects underlying cost imposed by all generators.

In the absence of a demonstrated net benefit, then alternative charging regimes should be adopted i.e. postage stamped.

1.2.2 TUoS and the SEM design

The BNE cost assessments are a primary determinant of the CPM "pot" size. This includes an assessment of the location of the BNE generator, and thus the TUoS it would pay. For physical (not assumed) generators then the recovery of TUoS comes through CPM payments. Thus:

- the SEM bidding Code of Practice thus prevents the explicit recovery of such locational costs through bid prices; and

- the cost recovery route is not locational.

In practice, generators in different locations that were the same size, and had the same availability profile would pay different TUoS charges, but receive the same contribution to such cost from the CPM. Synergen considers that the locational charging of TUoS is thus inconsistent with the CPM design and the bidding rules on generators set by the RAs.

1.3 Preferred TUoS approach

Synergen would prefer to see all TUoS costs allocated to suppliers – a 100:0 split. It does not believe that TUoS charges seen by generators are well recompensed through CPM and cannot be bid in. To the extent that charges are passed on, the initial charging to generators in an un-necessary step pre socialisation via retailers. To the extent that these costs are not recovered, this is inequitable and restrictive to an efficient generator.

If the split remains 75:25 Synergen would favour a postage stamping of TUoS based on registered capacity (as network costs need to reflect the capacity of a generator, not its annual output). Further, there should be only very limited exclusions on the generators side from contributing to the generators share.

Synergen proposes that if generators continue to be charged TUoS then the de-minimis charging threshold should be reduced significantly e.g. 100kW. Rationale:

- 10MW is not capable of being robustly defended – historic figure that probably seemed "about the right level" and cut out only a small number of players at the time it was established.
- Increasing levels of smaller schemes shifts the balance of total cost spayed by larger players going forwards – this is not equitable.
- If small players get CPM payments directly (or should sensibly capture such benefits via sales prices to retailers) then they should be exposed to the cost of the network in the same manner as other players. By this Synergen means where an off-market sale reduces a suppliers pool volumes, and thus its CPM costs.

2 Transmission Loss Adjustment Factors (TLAFs)

Synergen believes that there is a need to reflect the cost of losses in both the payments to generators, and the payments by retailers. Given that the SEM's central payment mechanisms are harmonised across jurisdiction, it is critical that such harmonisation applies to other the treatment of elements of market design that impact on competitive position of generators, or their settlement revenue streams i.e. losses.

This section discusses (a) the allocation of loss related costs between classes of participants, and (b) the principles that should be adopted in the cost reflective allocation of such losses. Subsequently Synergen makes broader observations on the incentives that may be required to reduce the overall level of losses.

2.1 Equity issues

It is the relative location of increments of generation and demand that give rise to changes in losses levels. In a market that seeks to adopt cost reflective principles (as in some respects the SEM seeks to) it is important that the differential values of generation that meets demand (i.e. its delivered value to customers) and the cost of taking demand locationally are reflected in the payments to providers of services and consumers of electricity.

As Generator TLAFs are set annually, Synergen considers that, over time a number of factors beyond the control of the generator will lead to changes in TLAF values (either up or down). This includes changes in location of demand, new transmission investment and new generation location. Generators should not be insulated from these factors, but neither should they be wholly exposed to the impact of such factors.

Consequently, Synergen believes that in principle the allocation of losses between generators and retailers should be re-visited with losses allocated on both the consumption and production sides of the market. This should lead to a reduction in proportion of losses being allocated to the generation side. This loss allocation should also be factored into the scheduling and despatch regime to ensure the efficiency of both consumption and production activities.

2.2 Approach to allocating losses in a cost reflective manner

The consultation paper questioned whether losses should be allocated "as incurred". Having already commented on the allocation of losses between generation and demand, this section concentrates on the application of TLAFs to generators.

Whilst, at the highest level, it may seem reasonable for losses to be attributed on the basis that they are incurred, the application of this principle will be problematic with respect to both the overall level of losses, and any costs reflective dynamic allocation. Under the SEM design, the generator sale occurs at the commercial boundary – and it has no control over the costs of delivery beyond that point. This consequently represents the limit of a locational signal that can be efficiently sent to a generator.

Allocating losses "as incurred" could be interpreted in a number of ways, but implies a full dynamic allocation of costs (potentially on a marginal basis). Synergen would not favour this because, the level of losses and the differentials in marginal losses particularly, could be driven by factors:

1. outside the control of the generator;

2. reflect constraint costs that arise in part through the energy pricing mechanism, and

3. occur beyond the commercial boundary.

Subject to incentives to reduce losses Synergen believes that TLAFs should seek to reflect locational values (at the commercial boundary), in a manner that is stable within year. In short, Synergen would not support any significant change from the current methodology.

Furthermore, there is a requirement for stability within the TLAF process given that generators are directed by the RAs to capture the TLAFs within the daily ex-ante commercial offer data. Variability regarding the allocation of losses would require internalisation of these risks by generators and hence would rightly lead to a risk premium being included within the bidding process which may distort the despatch / prices setting process. Consequently, Synergen is not in favour of the dynamic allocation of losses.

2.3 Incentives to reduce losses

Given that the overall level of losses is driven not just by the location of generation but also by the location of centres of demand as well as by actions by the TSOs / SOs e.g. constraint management. Consequently, Synergen believes that there needs to be appropriate incentives on the TSOs to minimise losses – where it is efficient to do so i.e. (a) minimising losses did not give rise to incurring other costs (where there is no incentive to minimise such costs) and (b) that any cost incurred by the TSO were not ultimately recovered from participants through TSO charges. This could be through specific price controls, or potentially the TLAF cost allocation.