NIE Energy Limited
Power Procurement Business (PPB)

Locational Signals Project: All-Island Generator TUoS

Consultation Paper

SEM-11-018

Response by NIE Energy (PPB)

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Power Procurement Business

Introduction

NIE Energy – Power Procurement Business (“PPB”) welcomes the opportunity to respond to the consultation paper which seeks views on the TSOs’ recommendations on a number of specific issues relating to the implementation of locational signals on the island of Ireland.

General Comments

At a strategic level, PPB is disappointed with the SEM Committee’s decision to adopt partial locational TUoS charges for generators as we do not believe it will have any influence on the decision making of generators with regard to location and will not help promote efficient network investment or least cost for customers.

It is further regretful that no analysis has been published to provide indicative tariffs (the SEMC decision paper indicated these were to be provided to the RAs during Q1 2011). Further, it would have been of benefit if the impacts on tariffs for each of the scenarios considered in this consultation had been set out as that would have enabled market participants to properly assess the impact of the options and assess the materiality of the impact on charges.

Specific Comments on TSOs Recommendations

1. Calculation Methods for All-Island Generator TUoS

We do not agree that it is critical for a common Generator TUoS tariff to exist on the island. There are many jurisdictional features that mean there are differences in input costs for generators in each jurisdiction. Differences, for example, include gas transportation charges, fuel excise duty, free carbon allowances under the respective NAPs, carbon levies, the UK’s proposals for a carbon price floor, general employment costs, local authority rates, corporation tax rates, etc. Such differences are further evident from the fact (as summarised on page 11 of the consultation paper) that NI generators pay TUoS charges 25 working days before RoI generators and therefore have higher working capital costs than their RoI competitors. There is therefore no rational reason to seek to develop a common charge for Generator TUoS charging that will inevitably, as outlined in the opening paragraph of Section 2 of the consultation paper, result in jurisdictional revenue flows that are in effect cross-subsidies between the jurisdictions, particularly where Supply TUoS charges are postalised.

Critically the extent of the cross-border revenue flows will depend on jurisdictional policy decisions that could result in much higher capital expenditure in one jurisdiction (for example noting the CER decision that allowed revenued in RoI will increase by c30% between 2011 and 2015) and relatively higher RAB values that inevitably will increase the extent of cross-subsidy such that generators in one jurisdiction end up contributing to support policy decisions in the other. Similarly, the level of TUoS revenue entitlement in each jurisdiction reflects historic investment decisions and relative operational efficiency differences between the jurisdictions which, under the TSO's preferred option, will mean generators in one jurisdiction will inevitably contribute to and provide a cross-subsidy to the higher cost jurisdiction.

Our strong view is that to the extent there is a desire for harmonisation of the methodology, then Option 3 would be the most appropriate option since it would ensure a common methodology is applied, relativity between individual generators in each jurisdiction would be maintained and as there would be no cross-border transfers required, billing and collection would remain jurisdictional and no currency exposure would be created. In addition, the risk to revenue recovery would not change and there would be no impact on Supplier charges. Similarly, should generators default in a jurisdiction, the revenue shortfall would be recovered within the jurisdiction, again avoiding cross-border subsidies.

The paper concludes that Option 1 has no impact on suppliers. However, while that may be true for Supplier TUoS, it ignores the fact that Option 1 will have an impact on the PSO charges faced by Suppliers in Northern Ireland as a consequence of any increase or decrease in Generator TUoS charges incurred by PPB in respect of contracted generating units. To the extent that such charges were to increase, this increase would <u>fully</u> flow through to PSO charges in N. Ireland and be reflected as higher PSO charges or lower PSO rebates. (We are not aware of the detail of the PSO contracts and associated arrangements in RoI but suspect a similar effect is likely).

In relation to the discussion on the mechanics of Option 1, we have already outlined above that we do not consider the option to be appropriate and all of the problems raised by the TSOs in relation to the mechanics (recovery mismatch, revenue receipt timing mismatch, cross-border flow risk, exchange rate risk) are not an issue under Option 3 and hence all of the added complexity (and cost) is avoided.

2. Fixed Tariff Options

The absence of any modelling to show the potential outcomes for each of the options makes it difficult to provide informed comments on the various options. For example, in relation to "step changes" under Option 1, or on the impact on suppliers from the alternative options, there is nothing to indicate the materiality of any volatility and hence it is only possible to comment on the conceptual effects.

A further issue that should be considered is the impact on the Capacity Payment Mechanism for each of the options since each is likely to have different implications for the derivation of the BNE price.

A further issue common to all the options is that a mechanism would need to be established to "standardise" exceptional events in the base year that could distort the modelling. For example, if in the base year a generator would be running at a higher load than would normally be the case because of a long term outage on an adjacent generator, and this would impact on the load flows and hence locational charge applied to the generator, that would be unfair and hence some form of normalisation mechanism would need to be devised to address such abnormal events that could affect the generator for the duration of the fixed period.

In the absence of being able to consider any analysis, option 3 may provide an appropriate solution but it would be useful, prior to taking any final decision, to review modelling of a range of scenarios to understand the remaining underlying volatility.

3. Non Firm Generator TUoS

We agree with the TSO conclusion that TUoS should apply equally to Firm and Non-Firm generators.

4. Distribution Connected Generators TUoS – Threshold level

We agree that the increasing levels of distribution connected generators merits a reduction in the threshold and 5MW appears to be an appropriate figure.

However, we strongly disagree that all distribution connected generators should not have to pay any TUoS on the first 5MW of their capacity. There is no rationale for such a move other than to remove a step change at the boundary. We recognise that there will be a step change for those generators currently in the 5MW-10MW band and there could be merit in providing some form of transitional relief or phasing[1].

[1] (e.g. where the capacity is between 5MW and 10MW, the effective capacity for GTUoS purposes could be determined using a formula such as (X-5)*2 where X is the capacity of the generator. In this instance, a 5MW generator pays nothing, a 6MW generator pays for 2MW, a 7MW generator pays for 4MW, etc. and a 10MW generator pays for 10MW)

Conclusions

The SEMC decision paper does not state that there should be an all-island Generator TUoS pot and we consider creating such an arrangement, as is reflected in the TSOs preferred option, will result in cross-subsidy from generators in one jurisdiction to generators in the other jurisdiction.

Critically, in respect of the generators contracted to PPB, any such cross-subsidy would actually be from Northern Ireland customers because PSO charges will be higher than they otherwise would be.

This effect is magnified where there is policy (and RAB) divergence in each jurisdiction which will increase costs to generators (and in NI, customers) to subsidise those policies driving increased transmission costs in the other jurisdiction.

We firmly believe that the jurisdictional revenue pots must remain and while a common methodology can be applied, the outputs of that process can be modulated to ensure full jurisdictional recovery while retaining the locational relativity within each jurisdiction, i.e. Option 3 in the paper.

The lack of any modelling makes it impossible to get a sense of the materiality of many of the issues relating to the options to reduce the volatility of tariffs and therefore it is difficult to provide reasoned comments on the appropriateness of the various options. We therefore consider that the option to maintain tariff relativity would likely be the most suitable but would prefer to see detailed modelling before any final decision is taken.

There has also been no consideration of the impact of the options on the determination of the BNE under the CPM, notwithstanding there is a relationship that must be considered.

Finally, we would highlight that as any locational element of the GTUoS charge is determined from usage of the network, it must therefore reflect anticipated scheduling and dispatch. This means there is effectively a “variable” element to the TUoS cost (in the same way as for generator O&M) that should be reflected in generators’ bids to ensure compliance with the Bidding Code of Practice. This should also be considered in terms of the impact of the proposals on consumers.