NIE Energy Limited
Power Procurement Business (PPB)

Principles of Dispatch and the Design of the Market Schedule

Consultation Paper

SEM-09-073

Response by NIE Energy (PPB)

18 September 2009

Introduction

NIE Energy – Power Procurement Business (PPB) welcomes the opportunity to respond to the SEM consultation paper relating to Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code (SEM-09-073).

We have structured our response to the consultation paper so as to provide some general high-level comments then more detailed comments in relation to the matters identified in Section 4 of the paper.

General Comments

We agree with the general thrust of the consultation paper in relation to the need to address the impact of the rapidly increasing penetration of renewable generation (particularly wind generation) on dispatch and the market schedule. However we believe that the issues posed by the projected levels of wind generation are broader than just dispatch and market schedule issues and we would urge the RA's to undertake more substantive and comprehensive review of the wider market arrangements to ensure that the overall arrangement of the Industry is sustainable, produces the least cost outcome for customers while protecting security of supply by ensuring all classes of investors can earn a reasonable return.

To be effective such a review needs to be considered and co-ordinated across all stakeholders in SEM including:

- Regulatory Authorities (RA's) – in relation to market design, bidding rules and connection policy;
- Government – in relation to policy and legislation covering Renewables, Planning, Licencing etc
- TSO's – in relation to system security, Grid Code, Connection Agreements, AS Agreements, Transmission Planning etc;
- Asset owners – in relation to managing and delivering the necessary infrastructure development;
- Market Participants – in relation to providing timely and consistent signals to allow appropriate investment/exit decisions, development of commercial strategies etc
- Customers – focus on providing choice and value across all customer categories

We believe that such a review must ensure that renewable generation is treated equitably within the market rules and should ensure that there are no barriers to entry. However, the market rules must not evolve in such a way that the SEM is distorted in favour of any particular generator grouping (in this instance renewable generation).

It is vital that the RA's recognise that renewable generation is already financially supported via a number of Government policy support mechanisms including the Renewables Obligation and Climate Change Levy in NI and the REFIT tariff arrangements in ROI. We consider there may be a risk that, without due care, the SEM could disproportionally increase revenue to renewable generators (via the inappropriate allocation of infra-marginal rent and capacity payments), to the detriment of the other generators, security of supply and as a consequence, customers.

We also believe that as the RA's and Participants consider how best SEM can accommodate substantively higher levels of renewable generation, other signals and mechanisms must be carefully considered including TUoS charging, locational pricing, the Capacity Payment Mechanism and Ancillary Service payments.

On the key issues of dispatch and market scheduling, we believe that the problems are exacerbated by the shallow connection policy that currently exists. Prior to Go-Live we argued strongly in favour of a deep connection policy, and given the risks identified in this consultation paper, we believe that there is merit in re-examining this issue to determine the most effective connection policy in the context of a system and market trying to accommodate substantial additional renewable capacity and to ensure T&D infrastructure development is optimised and costs are minimised.

We believe that renewable energy has a vital role to play in addressing climate change, and accept the need for the various national targets set by Governments in relation to renewable energy. However we are concerned that the development or revision of market rules in relation to dispatch, market scheduling and bidding must also be tempered with the risks associated with securing planning consents for major transmission infrastructure development often in remote, rural and heavily designated areas.

<u>Specific Comments</u>

1. Construction of the Market Schedule

We agree that 'export constraints' should by definition relate to those constraints caused by generation being commissioned and connected prior to the necessary transmission infrastructure being in place. This definition will need to be formally included within a range of relevant documentation including TSC, Agreed Procedures, Connection Agreements, Grid Code etc.

We note that the paper focuses on transmission connected generation, however there may be instances when renewable generation may be connected to the distribution networks and the impact of this within the SEM will need to be considered in terms of co-ordinating connection, dispatch etc between TSOs, DSOs and the relevant asset owners.

There is no doubt that with substantially higher levels of wind penetration, the mix of other generation plant will have to be able to offer more flexible operating characteristics than those prevailing today. We believe that such flexibility can be achieved in three ways:

1. Developing a market structure and rules which rewards flexibility and, where appropriate, provides an incentive for older inflexible plant to exit from the market;
2. New Ancillary Services which reward flexibility which can be offered by non-intermittent generators (e.g. warming contracts); and

3. Co-ordinated development of appropriate market rules and Grid Code Minimum Functional Specification (MFS) requirements to provide clarity for new entrants.

At this stage it is difficult to assess the optimum approach for providing flexibility, given the substantial caveats stated in the All Island Grid Study in relation to modelling the impact of such high levels of renewable penetration.

PPB has previously raised with the RAs our concerns associated with the current situation were there are units in NI and ROI which have non-firm access but which are currently being included within the market schedule and on occasion receiving infra-marginal rent. Of more significance is the fact that such units are receiving capacity payments even though they may not be capable of being dispatched to meet customer demand, thereby diluting the capacity pot and reducing the capacity revenue to units which have firm access. We therefore share the RA concerns that by including non-firm generation in the market schedule which cannot be actually dispatched (due to an export constraint), other generators which are constrained on to cover the non-firm plant will not be receiving infra-marginal rent. We also agree that this will have the effect of suppressing SMP in general in the short term, but may inflate costs for customers in the longer term.

We absolutely agree that the market structure and rules should not provide an incentive for a generator (renewable or otherwise) to construct plant before the necessary infrastructure is in place. Given the predicted level of wind penetration on the Island, to do otherwise would lead to an inefficient market, increase risks to system operation and ultimately have a detrimental impact on costs to customers in the long term. We are concerned that the RAs seem to believe that SEM must provide “appropriate signals for the right renewable and conventional plant mix”. Our view is that SEM must provide a level playing field for all generation technologies in terms of access, dispatch, bidding and inclusion within the market schedule. Wider Government policy in relation to renewable energy should provide the relevant support mechanisms to achieve national targets.

We welcome the RA’s deliberations on how best to mitigate the risks associated with the above via monitoring the relationship between actual dispatch and the construction of the market schedule. However there will be a need to avoid un-necessary or inappropriate regulatory intervention and any such monitoring must be transparent, robust, and consistent with specified policy/criteria, otherwise it may just increase regulatory risk and the cost of capital.

2. Curtailment

We understand that under the current market arrangements, curtailment would apply only to Price Taking Generating Units (which do not therefore form part of the market schedule) in circumstances where such units are constrained off due to system security/stability concerns. In such circumstances there is no ‘compensation’ payment.

If, given the likely increase in wind capacity, wind generators were required to register as Variable Price Making Units, the units would be in the market schedule and would have access to constraint payments, if they were dispatched off for system reasons. This seems like a logical and rational approach which we explore in more detail later (in section 7).

We agree that if new generation which cannot be dispatched due to an export constraint is to be disallowed from accessing the market schedule then there is no need for a separate concept or definition of curtailment.

3. Technical Constraints

In terms of future system requirements, particularly in relation to inertia and fault level in-feed, we do not believe that this should be included within the market schedule and indeed we believe that given the limitations of the MSP software, it would not be capable of accommodating such technical elements (or even if it could it may not be capable of doing so within suitable timeframes). Furthermore, participants who wish to undertake their own modelling and analysis of the market as part of business planning and risk management processes, are likely to find it difficult to do so on a meaningful basis, given the complexities associated with reflecting inertia and fault level in-feed parameters in dispatch models. Such uncertainty will increase risks to both existing and potential new participants.

The All Island Grid Study acknowledged limitations in relation to high renewable penetration scenarios and significantly, recommended undertaking further studies in relation to dynamic behaviour of the system and also detailed network planning studies to determine the impacts on the transmission system and generator connections. Given these recommendations and the current uncertainties around inertia, fault level in-feed, reserve requirement etc we would suggest that it is vital that the TSO's and asset owners to undertake this analysis as soon as practicable on a transparent and inclusive manner.

Only when such detailed analysis is completed and made available, will it be possible to determine the best way of addressing any impacts. We believe one way of mitigating some of the technical impacts would be for the TSOs to seek additional ancillary services (such as inertia etc) which would be secured from new and existing generators. We also accept that another option would be to include inertia and fault level in-feed requirements for new generators within Grid Code and Connection Agreements. However, it is not possible to decide which is the optimum solution without the detailed studies, data and assessment being made available to interested parties.

The issue of Grid Code compliance is a vitally important one and we have been concerned since SEM Go-Live about the significant number of Grid Code derogations that exist in ROI versus NI. Given the current lack of transparency with respect to TSO constraint decisions, it is difficult to quantify or assess the impact of such derogations on the market schedule, SMP, and constraint payments and we are concerned that different approaches to granting derogations could be distorting the market North versus South. This issue has also been discussed with the Harmonised Ancillary Service work-stream, but the position seems to be that plant with existing derogations, will only be penalised against derogated Grid Code values, and so the current SND, Trip Rebate and GPI incentives are unlikely to significantly improve Grid Code compliance for existing generation units, which are already limiting flexibility on the system. Furthermore, the new arrangements for GPI's, SND and Trip Rebates have yet to be implemented and it is not clear how effective these arrangements will be in ensuring Grid Code compliance going forward.

With such a substantial increase in renewable generation being forecast it is vital that the TSOs review the Grid Code on an ongoing basis to ensure that appropriate obligations are in place such that new generation does not compromise the safe, efficient and secure operation of the system. In parallel with Grid Code, the Authorisation procedure for new generators should require compliance with an appropriate Minimum Functional Specification (as developed by the TSOs) so as to afford clarity and consistency of treatment for all new generation. For new generator units that cannot comply with Grid Code or MFS requirements, derogations should only be granted in very exceptional circumstances and only if such units carry the cost of non-compliance. In addition, given the harmonised nature of the market and Grid Code we would suggest that the RA's should consider a more harmonised approach to the consideration and determination of Grid Code derogations.

We note that the consultation paper is silent on the impact of high levels of wind energy on the gas network. With such high levels of wind penetration, the necessary flexibility to manage such variable generation will be delivered via gas fired CCGT's and peaking units. We have a major concern that operators of gas fired plant will find it difficult to schedule and nominate gas in accordance with gas Transportation Code rules and this will increase the risks to security of supply. We believe that further work should be undertaken jointly with electricity and gas SOs to better understand the likely impact of such high levels of wind generation on the gas supply network and develop appropriate ways to mitigate and manage such risks.

4. Allocation of Access Rights

As indicated previously, we believe the current market rules already inappropriately allocate infra-marginal rent and capacity payments to units which have non-firm access. This problem will become greater with the rapid expansion of the connection of renewable generation and unless addressed appropriately, it will have a significant impact on the market and particularly on existing generators. Such generators have invested in plant and connections on the basis that their connection will be firm on a long term basis and we believe that such rights should not be eroded or expropriated by new generation connecting to the system.

We agree that the market rules should be developed to ensure that generators are not incentivised to invest in generation ahead of the capability of the networks to support it. Of the options presented we believe that Option 2 is the most effective option. It ensures that infra-marginal rents are appropriately allocated to units with firm access and provides a robust incentive on the appropriate parties (new entrant generators, TSOs and asset owners) to focus on the expedient and efficient development of the necessary infrastructure. We believe that option 1 would unacceptably diminish opportunities for existing generators to access infra-marginal rent, not due to competition, but due to export constraints. Furthermore, we believe that in terms of ensuring new infrastructure is developed in a co-ordinated and efficient manner, it is the new entrants, who require the connection, that are best placed to lobby and engage with the relevant parties to ensure that a rational approach to consents for both generation and transmission infrastructure are delivered as a package.

Option 3 may have some merit, however we believe that it may be overly complex and may dilute the focus on the need to develop the necessary infrastructure and it also increases the risk for marginal generators which may send a detrimental signal to potential investors and impact on security of supply in the longer term.

We remain concerned that generation granted non-firm access may still be able to harvest capacity payments even though they may not be capable of meeting demand and it is also unclear whether they are liable for TUoS charges whenever they are generating. There needs to be explicit rules to mitigate against this and an appropriate solution may be to limit capacity payments to the FAQ and apply TUoS charges up to the FAQ.

5. Deemed Firm Access

For many of the reasons explained above, we support the RA proposal that Deemed Firm Access should not be introduced to the SEM.

6. Dispatch Principles

We agree that a key objective of dispatch should be to achieve short-run efficiency by minimising the cost of production of meeting customer demand, cognisant of system security needs. However, in addition to this short-run efficiency, we believe that such dispatch efficiency should also apply to the management of constraints. Currently, there is a significant lack of transparency to market participants with regards to how constraints are managed by TSOs.

With such a significant increase in renewable penetration, we believe that TSOs should provide substantially more information to market participants in relation to the constrained dispatch. We believe that TSO's should maintain and publish a list of real-time constraints (due to either plant or system requirements) alongside a weekly report as to the nature of system constraints, impact on dispatch and associated costs.

We also believe that it will not be sustainable for wind generating units to continue to register as Price Taking Units and we believe that there is a strong case for changing the TSC to require all units to register as Price Making Units. This would assist the TSOs in terms of efficient scheduling and dispatch decisions and would also help address the problems posed by excessive generation events.

7. Priority Dispatch

This will be a key issue going forward with SEM, particularly given such high levels of renewable generation and other generation which may be deemed to be Priority Dispatch.

The TSC facilitates units which are designated as Priority Dispatch by providing an option for such units to register as either Price Taking Units or Price Making Units. Our understanding is that all wind and peat units in the SEM have opted for Price Taking status (either Variable or Predictable) and are therefore netted off demand, effectively ensuring that such units generate ahead of other units.

It seems that in the SEM, only units in ROI which fall under Section 39 (Public Service Obligations) of the Electricity Regulation Act can be deemed to have Priority Dispatch, although the term 'priority dispatch' is not defined in the Act or indeed TSO Licences. We note that there is no equivalent legislation or right in place within NI. We are therefore concerned that the use of the term Priority Dispatch is confusing in its application within the SEM and the TSC. Whilst we are not aware of any units in NI being deemed Priority Dispatch, where units are registered as Price Taking units then the effect is the same in terms of being netted off demand.

We recognise that Article 16 (2) (c) of Directive 2009/28/EC (RES Directive) requires Member States to "ensure that when dispatching electricity generating installations, transmission system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria". However this requirement and indeed all of Article 16 must be read and interpreted in the context of proportionality and indeed the other requirements detailed in the RES Directive. We do not accept therefore that the dispatch requirement equates to an absolute priority. Furthermore, a consequence of absolute priority would be to exacerbate the problem of inappropriately allocating infra-marginal rent and capacity payments, resulting in potential super-returns for renewable generators at the expense of other existing generators and customers, and totally undermine the efficiency and operation of the SEM and the transmission system.

We believe that the appropriate interpretation of Article 16 is that priority should be given to renewable generation only on a qualified basis and as necessary. However the need to objectify this qualified priority is relatively easily addressed by requiring renewable generating units (particularly wind units) to register as Variable Price Making Units. Renewable generator Market Participants could develop their own bidding strategies to reflect short run marginal energy cost of their unit (probably close to zero) and also include any relevant opportunity costs associated with carbon and renewable subsidies in their bids. This would result in renewable generators offering negatively priced bids to SEM, thus effectively receiving priority dispatch ahead of all other generating units on the basis of price. Furthermore, given the units would also be in the market schedule, on days when wind needs to be constrained down, constraint payments would apply in the normal way and the costs would be captured in a transparent and consistent manner. We see two key issues with this approach that will need to be resolved. The first relates to the need for clear, consistent and transparent rules for the TSO to apply when constraining units down (i.e. which units, on what basis and to what extent). The second issue relates to the uninstructed imbalance exposure a wind generating unit would face from despatch when it is registered as Price Making Unit. However, we believe these matters can be addressed.

In relation to peat fired units, we believe that such units should be registered as Predictable Price Making Units, bidding in prices which reflect their avoidable costs. In order for Eirgrid to comply with Licence condition 25 (in relation to the PSO), peat units could be constrained on and thereby achieve the priority dispatch requirement. This would allow the costs (or otherwise) associated with peat units to be captured and indeed levied across ROI customers as required by article 39 of the Electricity Regulation Act.

8. Hybrid Plant

We agree that the rules to be applied to hybrid plant should be contingent on how priority dispatch is resolved. However, given our proposal that all units should be Price Making units, we believe that this should apply to hybrid units. This approach would allow such units to reflect renewable subsidies and other avoidable costs associated with the renewable element of their output in their bids (see section 7 previous).

9. Variable Price Takers within SEM

We have detailed our view in section 7 that all units should be required to register as Price Maker units and in conjunction with our support for Option 2 in relation Access Rights, we believe that this would resolve the current and future issues associated with Variable Price Taking units. However, if no option is adopted in relation to Access Rights and Variable Price Taking units remain in the market, then we believe that such units should be limited in the market schedule to their FAQ.

10. Determination of SMP when demand is met by Price Takers?

Our proposal detailed in section 7 would address this issue.

11. Quantity of Generation Paid PFLOOR

Again our proposal detailed in section 7 would address this issue, as on an Excessive Generation Event the TSOs can constrain units off, with such units receiving constraint payments.

12. Tie Break Rules

If units continue to be allowed to register as Variable Price Taking Generating Units then it is likely that tie-breaking will be an issue for TSOs in determining which units to re-dispatch. The proposal that de-loading should be instructed on a pro-rata basis will be complex and difficult to implement in practice in a transparent and equitable manner. The configuration of individual installations, the connection infrastructure and associated control systems will dictate which units can be re-dispatched, to what extent and in what time-frame.

We believe that if units are registered as Variable Price Making Units, then the TSOs will have the necessary bid information to constrain down units on an economic basis. There should be a sufficient spread in the bids from Variable Price Making Units to ensure that tie-breaking decisions only happen in very rare instances. In such circumstances, simple rules could be developed by the TSOs, such rules being made available to all Market Participants.