BORD NA MÓNA ENERGY LIMITED

Submission by Bord na Móna Energy Ltd.

on

Principles of Dispatch and Design of the Market Schedule

Response to SEMC Consultation Paper

SEMC/09/073

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Introduction

Bord na Mona welcomes the opportunity to respond to the consultation paper on Principles of Dispatch and Design of the Market Schedule, to address the potential adjustments to the current trading arrangements that will likely be necessary in the medium to long term. At the outset we would like to make it clear, that given that the SEM is less than two years in existence, no significant changes to the fundamental design of the market could be considered necessary at this point in time. However, we are acutely aware that issues are likely to arise in the future which may give rise to the need to amend elements of the market and these issues should be flagged well in advance so as not to create uncertainty for market participants. Once issues are identified as part of this consultation process, trigger points should be clearly established for the implementation of any proposed changes to even minor elements of the market's architecture.

The context outlined in the paper is that the electricity market will undergo significant changes over the next 10-15 years, primarily relating to the need to increase the levels of electricity generated from renewable sources in order to contribute to meeting mandatory renewables (RES) targets. These targets must be achieved whilst providing a safe and secure supply of electricity to consumers at a reasonable and cost-reflective price. The argument is made that the current market arrangements, though working well for the current market conditions, will not necessarily give the correct economic signals to develop the portfolio which delivers the least cost to the consumer in the longer term, and ensure the 40% RES-E target is achieved.

Consultation Objectives

Given this context, Bord na Mona considers it is timely to review the market arrangements, with a view to gaining a common understanding as to the principles which will guide any future changes to the SEM trading rules. In this regard, Bord na Mona does not believe that the current process needs to define a prescriptive list of adjustments to the current T&SC arrangements, as in general terms the current arrangements are adequate and fit for purpose at this time. It should, rather, give an indication from the SEMC of the changes that may be implemented over the course of the next decade to deal with issues such as the management of constraints on an underdeveloped transmission network, the treatment of priority dispatch for renewable generation and the principles by which the System Operators plan dispatch schedules under increasing levels of uncertainty. We would consider that it will be necessary at this point to indicate "trigger points" which would result in the proposed changes being implemented in the future.

Whilst the consultation has raised a number of important questions, the workshop and further discussions with the RAs has emphasised the fact that there likely to be many issues that have not yet come to light, and there is need to take time before any significant adjustments to the market are made. It was clear from the feedback from market participants given at the recent workshop in Dundalk that there is a degree of comfort with the current market structures in general, and there is no appetite to make significant changes to the market design in the near future.

Taking these factors into consideration, Bord na Mona believes that it is prudent to spend some time over the questions raised in this consultation process. The purpose of this exercise is to signal the types of changes that will be appropriate as the generation portfolio evolves over the next decade, to one with large scale penetration of intermittent renewable energy sources. Some of the issues raised are more complex than others, and there is merit in running further consultations, including modelling where appropriate, to examine in more detail the feedback from this process. Any changes to market structures that are determined necessary should also consider when such changes be adopted, by establishing "trigger points" such as a certain penetration of wind power in the total energy mix, for example.

Interaction with other parts of the market

The other general point that arises out of the consultation is that the matters considered in the current consultation cannot be treated in isolation to other parts of the market, and other factors which are external to the market. The fundamental features of the market are the capacity payments mechanism, (CPM) which goes hand-in-hand with the marginal pricing structure of the energy market, and to a lesser extent the Ancillary Services (AS) market. All three of these elements contribute to the viability of generating plant, and have therefore a level of significance in the determination of the portfolio mix in the market.
One of the most telling results from the modelling work that was carried as part of the preparation of this consultation paper was the low level of inframarginal rent available to conventional plant in the future under the current market arrangements.The best case scenario for conventional plant arising from these model results showed that they only collected approx 25% of the total inframarginal rents allocated, whilst responsible for producing the majority (up to 60%) of the electricity supply in 2020. The numbers of CCGT and OCGT required in the model to give the necessary backup to the level of wind generation envisaged, suggests that for mid merit units, the levels of inframarginal rents, on top of capacity payments as they are currently constructed would certainly not be enough to make a mid merit CCGT plant viable in this market. With only BNE peakers (OCGT plant) effectively incentivised under the current arrangements, this may lead to an oversupply of energy from this units as opposed to the more efficient CCGT plants, and would be sub-optimal in terms of both price impacts and in terms of emissions levels.

There is a need to look at this issue holistically, considering not only the design of the energy market, but the related issues of capacity and ancillary service payments. There is also a significant interaction with the renewables facilitation process currently being carried out by Eirgrid, which aims to redefine the obligations of generating plant in terms of offering flexibility to accommodate the levels of renewable capacity required to meet the RES-E target of 40%, deemed necessary to ensure the mandatory 16% RES target is achieved by 2020.

Delivery of Renewables target

The Regulatory Authorities have stated explicitly in the paper and in previous consultations on this subject, that they have as yet no specific mandate to deliver the Governments' renewables targets. Whilst the SEMC has to pay due regard to these targets, their primary objective is to ensure that the consumers are provided with a safe and secure electricity service at a competitive, cost reflective price. This primary objective may ultimately act as an impediment to the delivery of the RES-E targets, especially where decisions required to ensure delivery of the targets may impact negatively on the price paid by the consumer

It is recognised that there are different RES targets set in the two jurisdictions in the market, but it is equally the case that increasing the penetration of electricity produced from renewable sources will bring longer term benefits to all consumers in the market, in terms of reducing prices, increasing security of supply and contributing significantly to the 16% RES for Ireland outlined in the RES Directive. Failure to achieve this mandatory target will result in financial penalties being imposed which will ultimately be paid for by the consumer/tax payer in any event. Bord na Mona believes therefore that it is imperative that the RAs should be specifically mandated to deliver on the specific RES-E target(40%), and a suitable all-island target should be set to allow for a joint SEMC approach to this issue. Any future changes in market rules or structure must clearly be assessed in terms of their impact on the potential to achieve the mandatory RES targets.

Specific Questions raised in the paper

Section 4.2 – Construction of the Market schedule

The principle of allocating inframarginal rent to plants which actively contribute to the dispatch schedule is a good one, and one which Bord na Mona supports, on the basis that it should incentivise the most appropriate plant mix that is actually needed to meet demand over the medium to long term.
It is difficult to uphold this principle in all circumstances, as has been demonstrated in the question relating to the correct scheduling of plants on the import or export side of transmission constraints. In this instance the imposition of this principle, whilst correct in the short term, may lead to sub optimal portfolio outcomes in the longer term. This is discussed further below, in the discussion on Section 4.5.

Section 4.4.2 – Resolution of new technical issues

The question posed at the end of this section is very open ended. However there is already strong evidence available that certain services, such as replacement reserve, will have more significance in future where the portfolio has a high proportion of wind capacity installed. Certain studies, e.g. the Poyry Intermittency study[1] have demonstrated the need for increased levels of replacement reserves and inertia on the system, with rising levels of variables renewables in the mix.

The key questions that arises out of the consultation paper are:

[1] Wind Intermittency: How wind variability could change the shape of the British and Irish Electricity Markets. Summary Report, July 2009. http://www.ilexenergy.com/pages/documents/reports/renewables/Intermittency%20Public%20Report%202_0.pdf

- how practical is it to schedule these types of characteristics in the market and/or dispatch schedules; and
- whether such scheduling can act as a strong enough incentive on it's own, without some form of additional remuneration, to ensure delivery of the correct levels of these services to the market.

Section 4.4.3 – Grid Code Compliance

This proposal suggests that compliance with Grid Code should be a mandatory requirement to participate in the market, and that is should continue to be policed outside of the market, by the regulatory authorities, as a condition of generator licences. Bor nM agree with the approach, and in particular the suggested review of the Grid Code.
The current Grid Code takes very little account of the differences between the capabilities and flexibility of the various the types of plant on the system, except for wind units. This 'one size fit's all' approach to generation plant doesn't differentiate the capabilities of the main classes of generator unit, in a way that could be used to signal the value of flexibility that plants could offer to the system. As previously stated, Eirgrid has started a significant renewables facilitation programme, which aims to address this important area.
Bord na Mona believes that the Grid Code should differentiate more clearly between different classes of unit, (steam cycle units, OCGTs, CCGTs, hydro, etc) much in the same way that the current code has a special classification for wind units. Once this exercise has been completed, it is then appropriate to review it on an ongoing basis, to reflect the capabilities of the best available technology as it improves into the future.

Section 4.5 – Treatment of Generators with non-firm grid access

This section discusses the allocation of access rights, with particular consideration of the impact of new generation accessing the transmission system without firm access capacity. In the example developed for illustration in this section, a new entrant generator with a low or zero marginal cost of production, is shown to have immediate access to the dispatch schedule, despite the existence of a regional constraint limit, and the fact that its connection status is financially non-firm. This example further demonstrates how the current market rules results in the displacement of an incumbent generator from the market schedule, who has firm access rights, and who is required to be dispatched because higher merit plants cannot be accommodated due to transmission constraints.

The example is illustrated in Box 2, on page 36 of the consultation paper, and the section proceeds to consider a number of variations on the current market rules, and their implication for the allocation of inframarginal rent to the generators in the example.

The current market rules, as have already been stated, requires that G2 in the example, be constrained on to meet demand, but allocates the inframarginal rent that accrues from the energy market to G1, which has a lower marginal cost of production, even though G1 does not contribute to meeting customer demand. This goes against the principle as discussed in Section 4.2, which requires that inframarginal rent should be allocated to units that contribute to supply, although in the longer term it does give the correct market signal to G2 when the transmission constraint is eventually removed.

Option 1 proposes that the inframarginal rent be allocated to those units that meet customer demand, which meets the objective of Section 4.2 in the short term. However, this option reduces the economic viability of G1 as long as the transmission constraint is in place. The economic signal to G1 whilst the transmission constraint is in force is to be replaced by a peaking unit, which is a suboptimal portfolio outcome in the longer term, after the transmission constraint has been resolved. It is could also be considered an unfair treatment of G1, which has been squeezed out of the market schedule primarily because of the decision of N to locate in their region, and because of the delay in delivering firm access to N by the system operator.

Option 2 protects the interests of both G1 and G2 because of their firm access status, and thus acts as a delay in the delivery of new capacity to the market, until such capacity has full firm access. This approach would likely put significant pressure on achieving the RES-E target, especially for plants who could not risk entering the market on a non firm basis. This proposal would result in a slow down in the rate of connection of renewable generators and would lead to higher market costs to the consumer, although this may be counterbalanced by a reduction in the level of supports that would have to be paid to renewable generators.

Option 3 is a variant of Option 2, which proposes that unused firm access could be allocated to non firm plant. This proposal should offer some level of additional inframarginal rent to new renewable generators. However, this additional margin would be location dependent, and likely be quite volatile and un-predictable.

In the overall consideration of these alternatives, Bord na Mona is of the view that the relative merits of each option would not justify changing from the current market rules for the treatment of units with non firm access in the market schedule. As stated previously, the current T&SC approach provides the correct long term signal, and the worst case potential outcome that could arise is that the market signal for G2 to be replaced by a peaking unit would occur a number of years early, i.e. whilst G2 is still required to meet a significant level of dispatch. This would result in a more expensive outcome for the consumer, who would have to carry the constraint costs associated with the running of G2. However, this outcome would also act as an incentive for the SEMC and consequently the TSOs to accelerate the delivery of the necessary reinforcements, to enable G1 to once again start contributing to meeting customer demand.

Section 4.6 – Deemed firm connection

This section considers the concept of deemed firm connection, where a generator may be allocated firm access rights ahead of the completion of any necessary deep reinforcements to the grid.
Bord na Móna support the proposal to prohibit a generator receiving 'deemed' firm access, as it is consistent with the principle as discussed in Section 4.2, that only those units which can contribute to meeting customer demand should be allowed to share in the inframarginal rent that accrues in meeting this demand.

If adopted, this proposal should not act to allow the System Operators to abdicate their responsibilities in providing the necessary reinforcements within a reasonable timescale. In this regard, it is appropriate to incentivise the System Operators, to ensure that deemed firm access dates are met within a reasonable tolerance, and that undue delays will result in a level of compensation being paid from the System Operators to the affected generator. The balance of the risk carried by the System Operator and the generator, in relation to delays in achieving the deemed firm completion date, could be agreed at the time of the connection offer.

Section 4.7 – System Operator principles of dispatch

The proposal in this section states that the System Operator should dispatch the system subject to the least cost of dispatch, regardless of the status of firm access to the grid. Bord na Mona agrees with this principle, as it promotes the most efficient use of resources and sets the best value prices for the consumer.
The main issue that arises from this proposal is the potential curtailment of low cost renewable generation that might arise in setting a least cost dispatch schedule to avoid expensive cycling costs for thermal plant. These issues are discussed in the response to Section 4.8 below.

Section 4.8 – Definition and treatment of priority dispatch

This section of the consultation looks at a number of options for the treatment of priority dispatch in constructing the dispatch schedule. Section 4.7 above sets a principle that the System Operators should schedule plants to provide the least cost dispatch schedule. However, even though wind power has a small, or in some cases negative marginal cost of production, it may end up being curtailed in a least cost production schedule, to avoid entailing significant cycling costs for large thermal plant.

Priority Dispatch is afforded to renewable generation plant, under the new RES Directive[2], subject to the needs for system operators to provide a safe and secure electricity supply. Priority dispatch is also afforded to certain non – renewable plant, principally the peat plants in the Republic of Ireland. These issues are discussed separately below.

The Legal Basis for Priority Dispatch of Peat Fired Plant

The question as to the legality of the priority dispatch status which has been afforded to the peat plants arises in the consultation document and was referred to at the workshop in Dundalk. Bord na Móna has received legal advice to clarify this issue as follows:

The legal basis for the priority dispatch of the peat plants subject to the Public Service Obligation (PSO) is defined in Article 21 of Statutory Instrument (S.I.) 217 of 2002 - Electricity Regulation Act 1999 (Public Service Obligations) Order 2002.

[2] Directive 2009/28/EC

This order introduced the public service obligations in respect of electricity generation in Ireland. The obligations covered peat and renewable, sustainable or alternative forms of energy. Article 21 deals with priority dispatch as follows:

*"21. The Commission shall direct that the transmission system operator, where applicable, **give priority of dispatch** to generating stations, the output of which is the subject of this Order."*

S.I. 217 of 2002 -Electricity Regulation Act 1999 (Public Service Obligations) Order 2002, has not been amended or repealed in any subsequent legislation and therefore provides the clear legal basis for the priority dispatch afforded to the peat plants.

Definition of Priority Dispatch

Section 4.8 poses a high level question vis-à-vis the precedence of affording priority dispatch to certain plant over the principle of dispatching all plants at least cost. In this regard, it questions the definition of the priority dispatch as proposed in the RES directive, suggesting it could refer to an absolute priority for renewable plant, or a more qualified priority, where they would have to compete with conventional generation for dispatch according to some economic measure of their cost of generation. The consultation paper suggests a number of alternatives as to how this qualified interpretation of priority dispatch may be put into practice.

In the first instance, Bord na Mona believes that the correct interpretation of the RES Directive is that it affords an absolute right of priority to renewables to the electricity system. The main reason for this interpretation is that it gives the largest potential penetration of renewable energy in the electricity market, which is the primary principle of the RES Directive. It is acknowledged that this may impose an additional cost through the energy market – however this cost reflects the true cost of renewables to the consumer, and is therefore consistent with the principle of price reflectivity.

Secondly, if you take the example of renewables with a relatively high marginal cost of production, such as biomass, a qualified priority dispatch offers no real advantage to this form of renewable generation, if it has to compete on an economic basis with conventional plant in the dispatch schedule. The economics of this type of plant can only work where the plant is guaranteed a high capacity factor, to allow for the development of a steady supply chain, and recoup the downstream investment in storage facilities, chipping equipment, haulage infrastructure, etc.

The modelling work which was used to give context to this proposal indicates that the total cost of the annual production schedule where the marginal cost of wind was bid to -€1,000 /MWh compared to a schedule where wind was bid at approx €0/MWh increases on a net basis, allowing for changes to interconnector trading, by approx €42m. In this case the shortfall of inframarginal rent to wind generators would have to be up by the support mechanism in place, such as REFIT. Thus the net impact on the customer is likely to be neutral, given that the support mechanisms such as REFIT are ultimately remunerated by the consumer through their PSO levy. If the support mechanisms don't make up the shortfall in revenues for renewable plant, the viability of renewable generation, and hence the achievement of the RES-E directive will be called into question.

There are a number of options proposed in the paper on the appropriate mechanism to bid renewables into the market. Of these, the two main options for consideration were the proposals to bid renewables at their avoidable cost of generation, either including or explicitly excluding the support mechanisms in place to support them.
As has been mentioned already, it is difficult to justify the case that bidding in the avoidable cost of generation for a renewable energy source such as biomass could offer any form of priority relative to mainstream conventional plants, which will typically have lower avoidable costs. The alternative proposal, where a generator could bid allowing for any remuneration that will be forthcoming from renewable support mechanisms, presents further difficulties, in relation to differences in the support structures in the two jurisdictions in the market. In the Republic of Ireland, the REFIT mechanism effectively offers a floor price for generators who are dispatched by the system operators. This proposal would therefore allow such a generator to out-bid any conventional unit, as the generator will always be compensated back to the floor price, regardless of how low the market price falls, so long as the unit is physically dispatched. In effect, therefore, bidding a REFIT guarantee on top of the avoidable cost of generation is equivalent to bidding at minus infinity, which would offer a level of access to the dispatch schedule equivalent to that where the plant is afforded absolute priority, as described in the paper.

In summary, therefore, BnM consider that the only practical option, and the option that maximises the contribution to the RES-E target, is the absolute definition of priority dispatch, and this should be maintained in the future market structure.

In relation to question (c) posed at the end of this section, the principle of absolute priority for renewable plant means that they should not be dispatched from their maximum level of output, except in cases where their dispatch is constrained for reasons relating to safety or security of supply.

The question posed in part (d) at the end of this section queries how non-renewable plant with priority dispatch by treated in relation to renewable plant. The simplest and most optimal solution, where plants with priority dispatch must be curtailed, is to curtail plant relative to their avoidable cost of generation, which will typically be higher for non-renewable generation. Alternatively, the SOs could use a hierarchical approach, where non-renewable plant are curtailed first, based on relative avoidable cost of generation before any hybrid plant and then any renewable plant is curtailed.

Section 4.9 – Definition of a hybrid plant

The concept of a hybrid plant is defined in the RES Directive as a plant which has a renewable fraction in its primary energy supply. It goes on to state that this plant should be afforded priority dispatch in proportion to its renewable percentage of the primary energy consumed by the plant.

Bord na Móna consider that there is merit in considering a de minimis threshold percentage for the affording of priority dispatch status to a hybrid plant, to ensure that

such plants make a reasonable commitment to provision of renewable electricity.
There would also be a significant administrative and operational burden in providing a level of priority dispatch to plants which generate insignificant levels of renewable electricity.
The determination of the appropriate de minimis level to be considered a hybrid plant would be a matter for further consultation. In relation to Bord na Mona's own activities in this area, namely the co-fuelling programme at the Edenderry power station, the company considers that a 10% threshold would be appropriate to demonstrate such a significant commitment. It would also be difficult to put in place the necessary contracts for procurement, processing, storage and delivery for a higher proportion than this without a level of guarantee in relation to dispatch. This target may be different for other plant types. (i.e. technology specific), subject to different technical, logistical or security of resource supply constraints.

The development of a reliable biomass supply chain requires significant investment in forestry or suitable energy crops, developing certified sorting programs for sourcing clean biomass from waste streams, harvesting and transport equipment, storage facilities and processing plant. This investment can only be secured by offering a medium to long term contract to a supplier/processor/haulier, which in turn requires a degree of certainty in relation to dispatch of the power station.

There are a number of potential options that could be considered in this regard. One option would be to afford a hybrid plant a level of priority dispatch to its minimum stable generation, which would allow the plant to consume a relatively steady stream of its renewable fuel, whilst having a minimum impact of the rest of the market. The plant would be subject to competing in the market schedule for higher levels of output, as a price maker plant. A potential downside of this option is that the heat rate for the plant is higher at minimum stable generation, which erodes part of the benefit of co-fuelling if the plant were to be dispatched at this level for a significant period of time.

It might be more optimal to allow the plant priority dispatch for a higher intermediate level of output, where the heat rate is more favourable. This option could be linked to the unit consuming a higher proportion of biomass in its energy mix, with the selection of the level of priority dispatch depending on the level co-firing rate achieved by the plant.

Other options that could be considered is to give priority dispatch for a certain amount of time or output per year, although both these options would not be compatible with the need to deliver the huge amounts of biomass materials in a steady state manner throughout the year.

Section 4.10 - Treatment of VPTs in the market schedule

The proposal to treat variable price takers in the same manner as variable price makers, both of which have the same rights to priority dispatch, is appropriate, on the basis of the principle of rewarding plants to the level to which they can contribute to meeting customer supply.

Section 4.11 - SMP in excessive generation events

This section proposes a number of alternative options for the setting of SMP in excessive generation events, relating to the options discussed in Section 4.8 relating to the treatment of priority dispatch plant in the dispatch schedule and by corollary the market schedule. Bord na Móna have argued for maintaining the current treatment of variable price takers, where they are effectively treated equivalent to price makers bidding at a price of minus infinity. In this regard, it is appropriate that the SMP is set to PFLOOR in an excessive generation event, where the demand can be met entirely by price taker generators.

Section 4.12- Quantity of generation paid PFLOOR in an excessive generation event

The proposal in this section is correct in setting the maximum quantity of generation which has to pay the PFLOOR SMP to metered generation. It is also reasonable in this case, that each unit's MSQ be pro-rated to sum in aggregate to the metered demand for the trading period in question.

Section 4.13 – Tie break situations

It is understood that a tie break situation, in the context of this proposal, relates to having to choose between two or more plants with identical avoidable costs of generation, e.g. choosing between two or more price taker wind farms. In this context, in Bord na Mona's view the proposal to de-load on a pro-rata basis is the most simple and equitable.

Conclusions

A summary of the major points that Bord na Mona would like to raise in response to this detailed and complex consultation are given below:

- The outcome of this process, including subsequent consultations as appropriate, should propose principles which will guide specific changes to the Trading and Settlement Code in the future;
- There is a need for a more holistic treatment of market reform in relation to the RES-E objective, incorporating the energy and capacity markets, ancillary services and SO incentives, grid development and access strategies, Grid Code review and non-market support schemes;
- The mandate of the RAs should be extended to include the delivery of the 40% RES-E target;
- The SOs should dispatch generators to a schedule at least production cost, subject to safety and security constraints;

- The current T&SC rules in the treatment of plants with non-firm access in the market schedule, whilst not optimal in the short term, lead to the best long term outcomes for the portfolio, and should therefore be maintained;

- The definition of priority dispatch given in the RES Directive should be interpreted by the SOs as an absolute priority when dispatching plant;

- The legal basis for the priority dispatch afforded to the peat plants is given in Article 21 of SI 217 of 2002;

- Bord na Móna consider it appropriate that a hybrid plant consuming de-minimis level of renewable energy be afforded a level of priority dispatch, as allowed for in the RES directive. The paper proposes a few suggestions as to how this could be achieved;

- Bord na Mona agrees with the proposals outlined in the paper relating to Grid Code compliance, the treatment of Variable Price Takers and the setting of SMP in excessive generation events, the prohibition on deemed firm connection status, and the treatment of price taker generators in tie-break situations; and

- The issue of managing additional technical constraints in the market schedule are recognised, but there needs to be more clarity given on how such constraints could be practically implemented.

For and on behalf of
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