BORD NA MÓNA POWERGEN

Submission by Bord na Móna PowerGen

on

Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code

SEM Committee Proposed Position Paper and Request for Further Comment

SEM-10-060

Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code

Response to Proposed Position Paper – SEM-10-060

Introduction

Bord na Mona welcomes the opportunity to respond to the proposed position paper from the SEMC on the Principles of Dispatch and Design of the Market Schedule in the Trading and Settlement Code. The SEM has been in operation for just three years, and has, to date, largely achieved the objective of giving stable wholesale market prices to the consumer, which are reflective of the underlying costs of generation.

The paper clearly indicates that the continued success of the SEM, in its current form will be challenged in the medium term by the high proportion of intermittent renewable generation in the market. This challenge will be compounded if there are significant delays in constructing the associated transmission infrastructure required to securely dispatch high penetrations of intermittent generation. It is therefore appropriate that all market stakeholders consider the potential impact of these issues at this time, to determine if changes to the market rules are necessary, what changes may be required if any, and what are the timelines, or the trigger points that signal the need for change. It is imperative from the point of view of the stability of the market that any changes are proportionate, and only implemented where it is demonstrated that they are necessary for the continued achievement of the objectives of the SEM.

The primary obligation of the RAs, in protecting the interests of consumers is acknowledged, and Bord na Mona agrees that the effectiveness of market structures will be measured through the delivery of competitive energy prices. Both Governments have set energy policies which aim to significantly increase the penetration of electricity from renewable source by 2020. This will protect consumers against a reliance on increasingly higher priced primary energy imports, and the cost of complying with mandatory renewable and climate change targets.

It must be acknowledged, however, that the transition of the electricity market to a high renewables penetration will require significant investment in both generation and transmission infrastructure. The cost of funding this investment will be directly related to the level of risk perceived by the funders of this investment. It is therefore directly in the interests of the consumer, that the RAs ensure that the market design remains stable, and any changes are proportionate, and only introduced where absolutely necessary to the continued achievement of SEM objectives.

It is also recognised that the landscape of the electricity market will change significantly over the course of the next five to ten years, due to the increased penetration of intermittent renewable generation. The energy market will be driven by lower marginal cost renewable generation, and the load factors of conventional plant will fall of significantly, as the baseload sectors are displaced by renewables with priority dispatch. This will mean significantly less inframarginal rent for all plants, which will have two knock on effects:

(1) the renewables which are supported by the REFIT mechanism will require more support from PSO funds, as the market reference price falls relative to the REFIT guarantee price;

(2) The revenue adequacy for merchant plant which have no external supports will be challenged, unless some additional revenues streams can be provided.

Bord na Mona believes that in relation to the latter point, the role of Ancillary Services will play an increasingly important role in the revenue streams for merchant generators in the SEM. This mechanism can ensure that the types of service that will be required to maximise the physical dispatch of intermittent renewables, such as inertia, low min generation, fast starting and ramping, etc. can be provided . It also can be used to incentivise the mix of generation that will be required at that time. The key issue that needs to be addressed is whether this rebalancing of revenues streams for conventional plant will give sufficient income to incumbent generators and/or encourage new generation as required into the market. Whilst this issue did not form part of the current consultation directly, we would like to see the SEMC and the TSOs considering this important issue in relation to the continued development of the SEM towards a high renewables market.

Response to Specific Issues in the Proposed Position Paper

Issue 1 – Alignment of Market Schedule and Dispatch Schedule

The RAs have indicated in the proposed position paper that they want to set down the general principle that the market schedule and dispatch schedule should remain largely aligned, to ensure that infra-marginal rents are allocated to generators who physically dispatched in real time. In practice, there are a number of reasons why the market schedules (as devised under the current Trading and Settlement Code rules) and the dispatch schedule diverge;

- The System Operators have to dispatch additional plant in real time to provide sufficient reserves for the secure operation of the transmission system.
- Certain plant cannot be physically dispatched if they are located behind export constraints.
- The System Operators have to react in real time to unexpected events, such as the sudden loss of a plant. These dispatch decisions will not necessarily coincide with the optimal market schedule when the ex-post market runs are carried out.

The first issue is a feature of the market rules, which does not include the provision of reserve cover as a constraint in the unit commitment and market scheduling algorithm. Therefore the provision of reserves is provided on a cost basis, (where a unit is constrained to a level of output to provide reserve), along with the revenues provided through the Ancillary Services mechanism. If the reserve requirements were co-optimised with energy, it is likely that the overall costs of providing reserves as seen by the consumer would increase.

The second issue, relating to the impact of export constraints is dealt with in the second issue of the position paper below. The key issue is the timely development of the grid to minimise the impact of transmission constraints. Changing the market rules to allocate the inframarginal rent to those generators in the dispatch schedule will reduce the cost of constraints, but cause a greater increase in energy costs, resulting in

a net increase in the overall costs to the consumer. This is illustrated in a worked example in the discussion on issue 2 below.
The third issue is a feature of all markets, although the increasing levels of intermittency in both supply and demand will tend to put upward pressure on the constraint costs associated with an increased level of uncertainty.

The RAs have indicated that the current cost of constraints, which is of the order of €100m, is not at a level which could be construed as causing material and sustained harm to electricity customers on the island of Ireland. The paper also indicates that the TSOs have advised that these constraint costs are unlikely to escalate to a significant level over the next couple of years.

The approach proposed by the RAs is to determine a "material level of harm", which will be used to test when the divergence between the market and dispatch schedules require intervention to alter the market rules. The suggested criteria used to define a test include:

- protection of end customers;
- security of supply, and
- sustainability and facilitation of renewable targets.

At a high level, it is hard to see how any of the potential changes proposed, (particularly in relation to transmission constraints) would result in an improvement in the outcomes for consumers over the current market rules. This is because, ultimately, by adding additional constraints in the market schedule, the marginal cost of generation will increase. This increase is paid in inframarginal rent to all generators in the market schedule.
Bord na Mona believe that the most significant challenge to securing supply in the long term, will be ensuring that an adequate commercial case exists for conventional plant who will be required to provide approx 60% of electricity in 2020, but face falling load factors and inframarginal rent. The revenue adequacy for conventional plant is a much more significant question than any mis-alignment between the market and dispatch schedules, and should be addressed as a matter of urgency, as discussed previously in the introduction.
The main challenge for the achievement of renewables targets will be the impact of curtailment due to technical limitations on physical dispatch of asynchronous renewable generation, and whether the support mechanisms are adequate to develop a business case at that level of curtailment.

Issue 2 – Allocation of Inframarginal rents behind export constraints

Issue 2 discusses a specific issue that follows on from the principle discussed in issue 1 above. The RAs have suggested that any change forthcoming in relation to the treatment of firm access in the market schedule would only arise if the proposed test of material harm indicated a need to alter the market rules.
There is also an indication in the paper that the RAs favour the approach of option 1 presented in the July 09 consultation paper. This proposes to limit the market schedule quantities allocated to generators behind an export constraint to the export limit, and not on the basis of firm access rights.

The implications of implementing option 1 are threefold;

- For the consumer – the outcome of implementing option 1 will be an increase in overall costs to the consumer. In the case study used to illustrate the concept in the July 2009 consultation paper the total constraints and energy costs borne by the consumer are illustrated in the following table
  Note: this worked example compares the current market rules with option 1 for the case study used in Box 1 and Box 2 of the July 09 paper, with a total demand of 100 MW. It assumes all other costs to the consumer, e.g. capacity payments, are the same in both scenarios.

	Current Market rules	**Option 1**
MSQ	N & G1	N & G2
DQ	N & G2	N & G2
Total Demand (MW)	100	100
SMP (€/MWh)	20	25
Total Energy market costs	€2,000	€2,500
Total Constraint costs	€250 [= 50 * -€20 (G1) + 50 * €25 (G2)]	€0
Total consumer cost	**€2,250**	**€2,500**

  The table shows that focusing on the costs of constraints in isolation misses the bigger picture for the consumer. It also shows that whatever criteria of material harm that are used to assess the current market situation must equally be applied to the proposed options. In this case Bord na Mona believes that the option 1 will be more expensive for the consumer than the current market arrangements.
- For the achievement of renewables targets –the perception of regulatory certainty in the market remains a key issue, as it drives the cost of debt and equity funding for investment. If the RAs introduce significant changes to the market rules that undermine the position of generators, who had developed a business case on the basis of firm access rights secured for their projects, and paid for through TUoS charges, this will increase the risk premia that will be applied to funding for future investment. This will ultimately either act as a barrier to the achievement of renewables targets, or push up the cost of achieving these targets, which will ultimately be borne by the consumer.
- For incumbent generators – as in the previous point, the requirement by generators is to ensure that the rules are not altered in such a way that generators, who have committed investment on the basis of the current rules, do not have their business case undermined. The argument that such generators do not get inframarginal rent when physically dispatched is a transient issue, as it is related to the delay in developing the necessary transmission infrastructure.

As stated in our original submission, Bord na Mona sees no convincing case that any of the options proposed in relation to the treatment of firm access for generators located behind export constraints are less problematic than the current rules. The focus should be on how the roll out of the transmission infrastructure required can be expedited to meet the renewable development targets.

From Bord na Mona's perspective, a greater challenge that is not really addressed in the proposed decision paper is the issue of curtailment. The studies commissioned by EirGrid and SONI on the facilitation of renewables indicate that constraint issues will dominate in the short term. However, as the grid infrastructure catches up with generation capacity, and the levels of installed intermittent renewables increase to a level where its instantaneous penetration is limited for technical reasons, curtailment of intermittent renewables will become more significant than constraints.

The issues of constraints and curtailment will pose very significant challenges to the achievement of the RES-E targets, as the support mechanisms, (REFIT and ROCs) are linked to physical dispatch of the supported generation. It might not be possible to address this issue through changes to the Trading and Settlement Code rules. However, Bord na Mona believes that, now that the scale of curtailment issue is better understood, the support mechanisms need to be reviewed to ensure that there remains a clear commercial case for the development of the levels of renewable generation required to deliver the RES-E target.

Issue 3 – Least cost dispatch

The principle of physically scheduling generation on the basis of least cost dispatch is generally considered to be appropriate. However the strictest interpretation of this principle conflicts with other principles that are discussed in this consultation, such as priority dispatch for renewables. In principle, in order to maximise the benefit of the renewable generation infrastructure, it would be better that the maximum dispatch of renewables (subject to grid technical operational limits) be accommodated, and then dispatch any remaining generation required on the principle of least cost.

Issue 4 – Interpretation of Priority Dispatch

Bord na Mona agrees with the approach adopted by the RAs to take a more 'absolute' interpretation of priority dispatch in the market schedule. We believe that any other concept of priority dispatch does not provide any differentiation from non-priority generation in the market.
As discussed in our views on issue 3 above, we would not agree that this priority should be sub-ordinate to the principle of least cost dispatch. We do agree, however, that the priority should be limited by the technical limitation of dispatch imposed by the safe and secure operation of the transmission system. The TSOs should ensure that the maximum penetration of renewables that can reasonably be dispatched, i.e. safely and securely, is scheduled before scheduling any additional generation on the basis of least cost dispatch.

Issue 5 – Information provided by TSOs

Bord na Mona supports the concept that the TSOs continue to study and share their findings with all market stakeholders in relation to the challenges and operating regimes that will be required to maximise the physical dispatch of renewables on the transmission system.

Issue 6 – Grid code compliance

Bord na Mona believes that it is important that all market participants fulfil their obligations in relation to compliance with the grid code, to maximise the benefits that

can be achieved from the generation and transmission infrastructure, and to ensure equity of treatment for all market participants.
We do feel that the current grid code needs to be reviewed, as it places the same performance criteria on all conventional plant, (except for one or two minor exceptions), regardless of their size or technology type. Bord na Mona believes that different types of plant offer differing levels of services to system operators, depending on their technology type. For example, a large steam turbine offers more inertia to the systems, whereas an aero-derivative gas turbine offers greater level of flexibility. We agree that all generators should meet minimum performance standards. However, the delivery of additional performance over and above the grid code minimum should be remunerated through the Ancillary Services market, at a price based on the value that the service offers to TSOs in operating the transmission system.

Issue 7 – Deemed Firm Access

The RAs have indicated that they believe that there is no convincing case for introducing the concept of "Deemed Firm Access" into the SEM. The concept of Deemed Firm Access would act as an incentive on the relevant system operator to ensure all reinforcement works were completed by a back stop date. Whilst it is acknowledged that there are externalities in the planning and development of new transmission and distribution infrastructure, the relevant system operators should endeavour to use all resources at their disposal to ensure that generators are afforded full firm access as close as possible to the firm access dates indicated in their connection offers.
The RAs have indicated that they intend to incentivise on a jurisdictional basis the timely delivery of transmission infrastructure. It would be useful if the decision paper could give a brief summary of these incentive mechanisms.

Issue 8 – Hybrid Plant and Priority Dispatch

The 2009 consultation paper described Hybrid generating units as *"units which have a proportion of their output which is classed as renewable"*. This description could apply to peat generating units which co-fire with carbon neutral biomass, and also to waste-to-energy plants which have a proportion of biodegradable waste in their energy source. We believe that the type of priority dispatch that needs to be afforded to Hybrid plants may differ for differing types of plant.

Under the renewable energy Directive[1] (2009/28/EC), Article 16(2)(b) requires that Member States shall provide for either priority access or guaranteed access to the grid-system for electricity produced from renewable energy sources. Article 16(2)(c) also states that Member states shall ensure that system operators give priority dispatch to generating installations using renewable energy sources, in so far as the secure operation of the electricity system permits. Article 5(3) deals with **multi-fuel plants**, which use both renewable and conventional energy sources, and states that the contribution of each source shall be calculated on the basis of its energy content.

[1] *Directive 2009/28/EC on the promotion of the use of energy from renewable sources*. OJ L 140, 5/6/09, p16.

The Government's White Paper on Energy[2], published in March 2007, set a target for the peat stations of 30% co-firing with biomass by 2015. This target was also included as a key action, saving up to 900,000 tonnes of CO_2 per annum, in the National Climate Change Strategy 2007-2012[3] published a month later.

The introduction of a Renewable Energy Feed In Tariff (REFIT) to support biomass co-firing was announced by the Minister for Communications, Energy and Natural Resources in May 2010. Details of the support mechanism for co-firing are included in the National Renewable Energy Action Plan (NREAP)[4] submitted to the European Commission in July 2010. This indicated that support for biomass will be limited to 30% of the maximum rated capacity in any plant up until 2017; 40% of maximum rated capacity from 2017 to 2019; and 50% of maximum rated capacity thereafter.

Taking all of the foregoing together, it is clear that Irish Governmental energy policy supports the production of dispatchable renewable electricity in multi-fuel or Hybrid plants using biomass. Under the terms of Directive 2009/28/EC, this renewable electricity should be afforded some form of priority dispatch by the Irish system operator.

As outlined in the proposed position paper, the peat stations are currently afforded priority dispatch under the provisions of S.I. 217 of 2002[5]. Provided that the stations continue to use peat as their *primary energy fuel source*, this priority dispatch will continue up until 21st December 2015 for Edenderry Power Ltd., and until 2019 for Lough Ree Power and West Offaly Power stations. The principal issue then is how peat stations, co-fired with carbon neutral biomass, should be afforded an element of priority dispatch after the provisions of S.I. No. 217 of 2002 expire, in order to ensure Government policy in terms of the contribution biomass co-firing can make to the achievement of mandatory RES targets is realised.

It is Bord na Mona's understanding that the detailed Terms and Conditions for REFIT support of biomass co-firing have been submitted to the European Commission for approval, but that these Terms and Conditions are not yet in the public arena. Similarly, the provisions of Directive 2009/28/EC have not yet been transposed into Irish legislation, and no draft bill or order has been circulated for consultation. In the absence of both of the above, Bord na Mona proposes the following scheme for the priority dispatch of Hybrid peat/biomass plants.

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[2] *Delivering a Sustainable Energy Future for Ireland*. Department of Communications, Marine & Natural Resources, Dublin. March 2007.

[3] *National Climate Change Strategy 2007-2010*. Department of the Environment, Heritage and Local Government, Dublin. April 2007.

[4] *National Renewable Energy Action Plan – Ireland*. Department of Communications, Energy & Natural Resources, Dublin. July 2010.

[5] Statutory Instrument No. 217 of 2002: Electricity Regulation Act 1999 (Public Service Obligations) Order 2002.

As discussed in our response to the 2009 consultation paper, the peat stations are designed to operate efficiently at close to full load. While they can be dispatched down to minimum stable generation, there is a significant difference in the heat rate at this level of output. Bord na Mona does not consider the long term operation of these plants on partial load, close to minimum stable generation, to be a viable or economic proposition. It would be better to consume the volume of biomass, supported under the REFIT scheme, by operating the stations at higher load over a shorter time period.

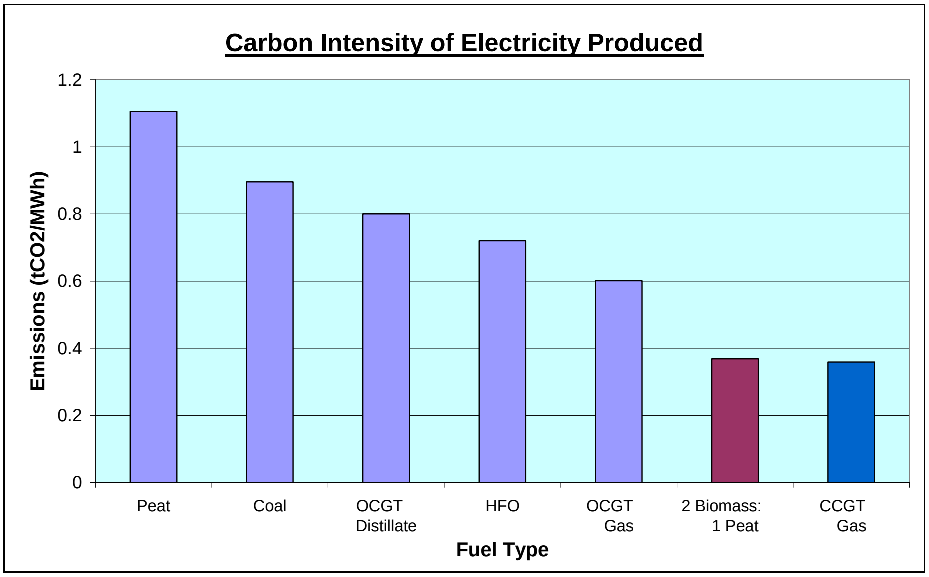
Plants afforded priority dispatch have the option of declaring as Price Takers in the SEM. We assume that this will continue in the future, and therefore peat plants co-fired with biomass could declare as Price Takers for the period during which they are granted priority. Bord na Mona suggests that this should be during the winter months, e.g. from October to April, when demand on the system is highest. During the remainder of the year, from May to September, these plants would change over to become Price Makers, running on peat and being dispatched if they are in merit. The benefits of this approach include:

1. Overall system demand is higher during the winter months. This should, in theory, provide more scope for Price Taking generation during this period of the year, and reduce the level of impact on the Price Making fleet;

2. SMP prices are, in general, higher during the winter months. Since the co-firing with biomass will ultimately be supported through the PSO Levy, burning biomass during the period of highest market prices will reduce the level of support needed from the PSO;

3. From our modelling of the SEM, overall market prices are lower by approx 0.7% when co-fired plants operate in this winter Price Taker/summer Price Maker mode;

4. Overall market emissions of greenhouse gases are likely to be approximately the same. The most likely plants to be displaced from the market schedule by Hybrid peat/biomass plants operating as Price Takers are CCGTs fired on natural gas. Since the Hybrid plant owners will be taking a price and volume risk on the non-renewable fuel during the Price Taking period, the amount of non-renewable fuel used will be minimised. Bord na Mona would envisage the use of a biomass:peat mix ranging from 1:1 to 2:1 during the Price Taking period. The comparative CO_2 emissions are outlined on the graph below:



This mode of winter Price Taker/summer Price Maker operation would be suitable for generating units that co-fire with biomass. However, it would not be suitable for waste-to-energy plants which operate continuously on a year-round basis. As stated at the beginning, Bord na Mona believes that all Hybrid or multi-fuel plants that produce a significant amount of dispatchable renewable generation should be afforded some form of priority dispatch. The specific form of priority will obviously have to vary according to suit the efficient operation of different plant types.

Issue 9 – Determination of SMP when Demand met by Price Takers

Bord na Mona agrees with the proposal to maintain PFLOOR as the minimum level of SMP in the market.

Issue 10 – Quantity of Generation Paid PFLOOR

Bord na Mona agrees with the proposal that in an excessive generation event, the amount of generation paid PFLOOR is limited to system demand, and that the scheduled quantities of units in such an event by pro-rated down so the aggregate scheduled quantity equals system demand.

Issue 11 – Tie Breaks

Bord na Mona agrees with the proposal, that where tie-break rules are required, de-loading should be instructed on a pro-rata basis in a manner determined by the TSOs.

Issue 12 – Treatment of Variable Price Takers in the Market Schedule

Bord na Mona agrees with the proposal, that the treatment of variable Price Taker generators be aligned with the rules for other classes of generator. Specifically, this means that their MSQ should be limited to their actual output or firm access quantity.

Summary of Key Points

- There is a need to maintain regulatory certainty in the market. The market rules should not be altered except to address a failure to meet the SEM objectives.
- There is a need to address the question of revenue adequacy for conventional plant as the levels of renewable generation increases towards the 2020 targets.
- There is no convincing case at this stage that closing the gap between the market and dispatch schedules will reduce the cost of electricity for consumers
- There is no clear case for changing the rules in relation to firm access. The preferred solution proposed in the paper would act to increase costs to consumers.
- The issue of curtailment is not addressed in the paper, but needs to be considered in relation to the adequacy of the support mechanisms for renewables.
- The concept of priority dispatch should be absolute, except where it impacts on the safe and secure operation of the transmission and distribution systems.
- There is a need for priority dispatch for hybrid plants, to ensure government policy in relation to biomass co-firing of peat plants and waste to energy plants can be achieved.

For and on behalf of
Bord na Mona PowerGen,

Brendan Connolly
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Brendan Connolly
Projects Manager,
Bord na Mona PowerGen.