SEM CONSULTATION ON THE PRINCIPLES OF DISPATCH AND MARKET SCHEDULE

A note from Pöyry Energy Consulting to the Irish Wind Energy Association (IWEA)

August 2009

EXECUTIVE SUMMARY

Introduction

Pöyry Energy Consulting has been appointed by the IWEA to review the SEM Consultation Paper 'Principles of Dispatch and the Design of the Market Schedule in the Trading & Settlement Code' (SEM-09-073), which was issued on 8 July 2009. In this Note we report the outcomes from our review. The views expressed are our own; they have been developed independently of the IWEA and do not necessarily reflect the opinions of that organisation.

Overview

In any electricity market a balance must be struck between the frequency of regulatory review of its operation and the desirability of maintaining stability to avoid unnecessary regulatory risk. The Consultation Paper raises fundamental questions over the high level SEM design – in particular whether the market should become locational for generators which have firm access – without adequately assessing the scale of any problem. In our view it is too soon after the introduction of the SEM for a major market review of this nature, and we believe that the Paper has introduced major regulatory risk to the market unnecessarily.

In relation to regulatory risk, most existing generators have a contractual agreement for firm access, in the sense that they are compensated financially if and when they are denied physical access; this point should not be lightly ignored. The market has successfully maintained a concept of non-firm access in parallel to the firm access provisions, and this flexibility has permitted generation projects (predominantly renewables) to connect and operate in advance of their firm access dates. This flexibility is missing in other markets (e.g. BETTA) and its value should not be undermined unnecessarily.

If and when there is to be a major market reform it must consider the potential integration with BETTA as a priority. To ignore this aspect in the assessment criteria is a serious omission and risks that the market develops in a way which makes future integration more difficult. Ultimately integration with the larger market is the most effective way of accommodating high levels of wind generation. It is also in line with European ambitions for the development of regional electricity markets.

The assessment criteria in the Paper do not include adherence to legal requirements (including the EU's latest Renewables Directive), or to government policy including renewable targets. Although there is debate over whether the delivery of government policies is a regulatory responsibility, this should at minimum be part of the assessment and ideally there would be a holistic view taken across regulators and policy makers. There is no doubt that operating within the law is part of the regulatory remit and therefore adherence to the EU Directive (at least as interpreted by the Governments) and other legal requirements should be part of the assessment.

Any proposed changes to the market should address incentives for both generation and consumption, in both the short and the long term, but the paper is effectively silent on consumption. Alongside integration with BETTA, the ability of the market to accommodate high levels of wind will in the long term be crucially dependent on demand side integration. However, the Paper concentrates on efficient dispatch and infra-marginal rent, and in doing so fails to consider the dynamic inclusion of the demand side, despite the fact that it is expected to be essential to achieving an effectively functioning electricity market with high levels of wind.

There appear to be four primary concerns raised in the Paper:

1. Given the delays in providing grid infrastructure to connect new generation, largely wind, there is a (perceived) shortfall in revenue to constrained on generators that need to run due to transmission constraints (which is cast as a lack of incentive to invest in generation in appropriate locations).
2. A further issue relates to the need for more flexible generation in system operation, due to the inherent technical characteristics of wind. It is argued that investment in the most suitable form of flexible generation is discouraged because of a shortfall in revenue to generators constrained on to support wind for non-transmission reasons.
3. There is also uncertainty over the interpretation and application of priority dispatch to both TSO dispatch decisions and access to the market schedule, and the ability to distinguish between different plants with priority dispatch when making dispatch decisions.
4. Finally a more fundamental issue for the market design, but dealt with less explicitly in the paper, is the ability to set a suitable SMP to correctly incentivise the most efficient generation and consumption decisions, both in the short and long term, in a world where subsidised price takers (or price makers with negative bids) might increasingly set the price.

Issue 1 – Lack of transmission capacity

The ultimate solution to this issue is to ensure that the necessary network infrastructure is built in a timely fashion, although the Paper tends to stray from this focus. In the meantime, given that wind resource is located in remote areas and the necessary Grid build will be delayed, we advocate that the market design should not hinder the delivery of wind projects. Indeed, this should have been one of the Paper's assessment criteria.

The most economically-efficient solution would, we expect, incorporate locational pricing, but this option has been explicitly rejected in the SEM high-level design and the annulment of the previous MAE market design proposals. Whilst a fully locational market may be part of the solution in the longer term, we consider that its partial introduction at this stage would be inappropriate because of the regulatory risk it would engender.

The various options for reform are based on the logical construct that the status quo delivers excess payments to generation behind export constraints and insufficient payments to generators behind import constraints (compared with a more economically efficient locational market). This effect is, however, a direct consequence of the approximations which flow from the high-level design of the SEM – with its unconstrained schedule and single nationally-uniform SMP. We note that the natural conclusion of the Paper's argument, of a move to complete locational pricing, has been excluded from the options without discussion. Moreover, there is insufficient analysis in the Paper to demonstrate that the issues raised will in practice lead to inappropriate investment decisions and therefore that the proposed options are necessary or appropriate.

Three Options have been put forward for dealing with revenue allocation issues arising from the delays in connecting new wind plant, and the absence of locational elements to the SEM schedule (in accordance with the high level design):

- Option 1 moves to a transmission-constrained schedule with no respect for firm access rights, which represents a major change to the circumstances of existing generation with firm access[1];
- Option 2 removes all opportunities for non-firm generation to achieve any energy payments and associated infra-marginal rent (excepting capacity payments and renewable support mechanisms), and appears to have little merit from any perspective; and
- Option 3 respects the distinction between firm and non-firm generation in the schedule and allocates some infra-marginal rent to non-firm when constraints are not binding, although less than the status quo for non-firm wind generation (even when it is running).

Of the reform options, Option 3 appears the least inappropriate of the three, and respects existing agreements for firm and non-firm access. (In fact, the relative rights enjoyed by firm access over non-firm will be increased somewhat beyond the status quo – to provide some degree of priority in scheduling, over and above the current financial compensation for being constrained-off.) However:

- Option 3 is likely to be detrimental for wind connecting in areas of transmission constraints compared to the status quo. This is despite the system benefiting from the output of the wind, which will remain as in the status quo (as wind will still be dispatched ahead of thermal generation on cost grounds).
- The adverse impact on the economics of existing wind generation (behind export constraints) will likely discourage investment in new wind projects, at least ahead of the time by which firm access can be provided.
- SMP will tend to be higher than under the status quo, and the additional cost (to consumers) is unlikely to be efficiently allocated to those specific plants currently constrained on for transmission reasons.
- The implementation cost for Option 3 might also be excessive compared to the actual costs of the transmission constraints themselves.

'Connect and manage' (termed 'deemed firm access', whereby firm access is granted to certain projects according to fixed timescales ahead of network build) does not appear to be considered adequately in the Paper[2]. We believe this to be a direct consequence of

---

[1] Although it would be possible to effectively "grandfather" the rights of existing holders of firm access, through the use of financial hedges.

[2] If 'connect and manage' were to be explicitly introduced, whereby renewable generation is awarded firm access ahead of network build, then the detrimental effect of Option 3 on wind

omitting the delivery of government renewables targets from the assessment criteria. We note that a similar review is being conducted into BETTA, and that 'connect and manage' is DECC's preferred option in GB to address a similar issue. We further note that the status quo for wind generation is in its effect close to 'connect and manage', due to wind's low variable cost or priority dispatch status. This enables it to be dispatched and also to access the market schedule (other than the exception – expected to be rare in the medium term – of non-firm wind that is constrained off).

All-in-all, we consider that the status quo is probably the best option taking into account all factors, including the expected level of transmission constraints compared with overall market revenue in the longer term. The capacity pot provides revenue for constrained on plants behind import constraints; although this will adequately reward only BNE peaking plant, these could be all that is needed. Alongside the status quo, incentives need to be put on the TSOs/TAOs to ensure that grid reinforcements are delivered in a timely manner.

Issue 2 – Change in system operation due to increased wind

This is a genuine concern, to do with a shortfall in remuneration for providers of reserve and flexibility to the system and the consequent discouragement of investment in such provision. Surprisingly, there are no firm proposals on this in the Paper, although it does mention the possibility of adding inertia, or reserve, to the schedule.

In our view, the issue should be addressed not by distorting the energy market or capacity payments, but by creating a separate stream of revenue, to the extent that reserve and flexibility are scarce products which need remuneration. The result should be market based, and could entail some directed payments (e.g. via ancillary services contracts) or alternatively a more dynamic solution in which reserve is priced as part of the market schedule.

There are already some flexibility constraints in the schedule, such as ramp rates and minimum-on and -off times. However, if plants are required with greater technical capability than BNE peaking plant, additional revenue needs to be found. This could be achieved through putting additional constraints in the market schedule (e.g. co-optimisation and a dynamically calculated reserve price) or through separate payment mechanisms.

The most suitable methodology will depend on the level of additional revenue required. There is no clear evidence that this is currently significant, although the shortfall is likely to rise in the future with increased wind. We suggest that a separate cost-benefit analysis be undertaken to assess the need for action in this area, and – if action is indeed indicated – to determine the most appropriate remuneration mechanism(s), whether within the schedule or outside of it.

Issue 3 – The impact of priority dispatch legislation and distinguishing between priority dispatch generation

A number of legal questions surround the issue of priority dispatch, including:

- What is the level of qualification, assuming that it is not absolute?

---

with non-firm access (compared with the status quo) would be mitigated by advancing its firm access.

- Should priority dispatch apply to access to the market schedule as well as to dispatch itself?
- Do some priority plants have greater priority than others?

The answers to legal questions need to be informed by legal advice. We cannot ourselves provide legal advice, and we have not sought it for the purposes of this review. With this proviso, we have based our views on a few reasonable principles – as follows:

- Actual dispatch should be undertaken on a least cost basis, and can in principle be kept separate from commercial matters.
- While the EU Directive is silent as to whether priority of dispatch also implies priority of scheduling, if wind is contributing to the system it is valid for it to receive infra-marginal rent (as in the status quo and, to a lesser extent, as in Option 1 above) – i.e. priority of scheduling is consistent with priority of dispatch.
- The interpretation of legislation, including European legislation, and of relevant government policies is primarily a matter for the Governments themselves. The SEM should not second-guess the Governments, but should be steered by the nature and magnitude of their policy interventions.

In this context, the Governments' policies for renewables are primarily expressed in the support mechanisms of the REFIT and the NIROC. We therefore support the principle of Option 2(c) in the Paper, 'Dispatching (and scheduling) taking into account subsidies'. Ideally, all generators should bid their own prices; for renewables, these prices would be net of subsidies. To this end all generators should be encouraged to become price makers and submit their own prices for use in dispatch and the market schedule; this would de-emphasise the priority dispatch issue.

Ultimately there will be a need to distinguish between priority dispatch plants of the same technology. Here again, the required distinctions would emerge from the process of cost-reflective bidding; for renewables, cost-reflection would require the netting-off of their subsidies.

The encouragement of price-making, and the discouragement of price-taking, would require the rebalancing of incentives between price maker and price taker status. To this end the RAs should review and remove any unnecessary overheads or administrative barriers to operation as price makers, particularly for smaller participants (such as the ineligibility of price maker generators to avail of the Intermediary arrangements).

A suggested solution would be to treat all residual price takers as if their bid price were PFLOOR in the dispatch and scheduling processes (not minus infinity as at present)[3]. This treatment of price takers is consistent with Option 2(d) in the Paper.

Issue 4 – Ability to set the SMP with a significant amount of low or negatively priced generation

As noted above, we consider that all plant should be encouraged to become price makers, as it will allow scheduling and dispatch to be in accordance with priorities as determined by the Governments' renewables support policies and, within this constraint, will result in a dispatch and an SMP which are more economically efficient than at present.

3 Another advantage in aligning the deemed bid price for residual price takers with PFLOOR is that it is the lowest price to which they are exposed.

The bids of those price makers with subsidies would often be negative. Price takers would be exposed to PFLOOR; if that were too low they would turn off or become price makers.

There is therefore the possibility that some outcomes will arise which might be considered undesirable – such as low or negative SMPs, and/or SMPs set by PFLOOR. If this were to be the case, then it would be the responsibility of the Governments to address their support mechanisms. They might, for example, reduce their levels of support – or place less emphasis on a per MWh production-based subsidy and introduce a capacity (per MW) or availability (per-MWh) based element instead. This would result in higher incremental costs, and hence higher bid prices, and would mute the incentive for renewables to maximise generation at times of low/negative SMP.

It could be argued that low and negative prices would encourage the growth of energy storage and of demand-shifting as means of accommodating large quantities of wind on the system. While this may be the case, the economics of these options should be driven by considerations of resource cost, not by arbitrary subsidy.

While we have argued that it is the Governments who would need to take responsibility for correcting any undesirable consequences of their policies, there would clearly be a role for the Regulatory Authorities both in considering the application of the policy where this is within their remit (such as the CER's overview of the PSO aspect of REFIT), and in bringing such consequences (actual or threatened) to the Governments' attention.

1. INTRODUCTION

This note has been prepared in response to the consultation document SEM-09-073 on 'Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code'. The note briefly:

- summarises the drivers behind the consultation paper;
- reviews the suggested principles for the dispatch decision and the construction of the market schedule; and
- provides comments on the various proposals set out in the consultation document.

1.1 Drivers of consultation process

The consultation document has been developed as part of a review of potential issues in the SEM arising from the expected increase in wind generation over the period to 2020 and beyond. This review, which started with a February 2008 discussion paper[4], reflects the targets for increased renewable deployment in both Northern Ireland and the Republic of Ireland. For example, the government in the Republic of Ireland has set a target of 40% of electricity generation to come from renewables by 2020, and the draft Strategic Energy Framework for Northern Ireland similarly proposes a 40% renewable target by 2020.

At high levels, the commercial nature of wind generation, with its high ratio of fixed to variable cost, presents challenges to the operation of an energy market which is based on the principles of short-run marginal cost pricing (albeit with additional reward for the provision of capacity).

1.2 Assessment criteria

We note that the assessment criteria set out in Appendix 5 of the document are incomplete. They should at least include an absolute criterion of compliance with legal requirements, such as the priority dispatch and access provisions set out in the 2009 Renewables Directive. In addition, it would seem appropriate for consideration of policy options for the SEM to take into account national and EU energy policy goals, such as the increased deployment of renewable electricity. In Northern Ireland, the SEM was enabled under the NI SEM Order in Council 9(5), which states that '*the Department, the Authority and the SEM Committee shall have regard to ... the need, where appropriate, to promote the use of energy from renewable energy sources*' (which, via a 1992 Order and a 2005 update, uses the same definition of renewable energy sources as the proposed Renewables Directive).

4 'Wind Generation in the SEM', Discussion paper, SEM/08/002, 11 February 2008

[This page is intentionally blank]

2. PRINCIPLES FOR THE DESIGN OF THE SEM

Principles for the design of the SEM are described in Chapter 3 of the consultation document. These are followed by proposals set out in Chapter 4 of the document. In this section, we review these principles, particularly in light of the delivery of an efficient market outcome, in terms of:

- short-term production (through the dispatch decision);
- short-term consumption (through market prices);
- longer-term (dis-)investment decisions for generation (through the market schedule and market prices); and
- longer-term consumption planning decisions (through market prices).

We note that market prices and the allocation of generator revenue and infra-marginal rents are intermediate steps in the delivery of efficient market outcomes rather than ends in themselves.

Below is a review of the proposed principles for the dispatch and the construction of the market schedule as set out on page 23 of the consultation document.

2.1 Principle i) – real-time dispatch should have the objective of minimising production cost (taking into account security considerations)

The first principle relates to dispatch decisions by the TSO and whether these should consider only economic costs or other factors. Centralised dispatch means that, in contrast with most markets, generation may be dispatched to meet demand at least cost in the SEM independently of the market price or the market schedule. The primary intent of this principle is that the access rights of each plant, whether firm or non-firm, should not be considered in the dispatch decision. We agree with this point, i.e. that dispatch should be instructed by the TSO without account of whether plant has firm or non-firm access since these are commercial issues, which should not act as a barrier to the achievement of a minimised production cost outcome.

However, we believe that the dispatch decision should also take into account legal requirements for compliance with the 2009 Renewables Directive in terms of priority dispatch for renewables. The RAs suggest that it may be appropriate to take cost into account within this prioritisation and potentially to take into account wider system costs, such as the impact on the loading and start-up of other costs, and total carbon emissions.

2.1.1 Implications of principle

The current SEM arrangements already allow renewables, peat-fired generation and designated CHP facilities to opt to be price-takers and hence effectively receive priority dispatch, despite there being no sound basis for this in law within either jurisdiction. This means that the dispatch decision at present takes account of price taking plant on the grounds of a fuzzy legal requirement with respect to priority dispatch.

Therefore, the principle set out above implies a change to the status quo to consider the dispatch of plant with the lowest generation costs, given the network capability and other technical issues. The proposed principle implies the retention of the concept of disregarding firm and non-firm access rights in the dispatch decision.

2.1.2 Implications for wind generation

In practice, a move to dispatch based purely on generation costs is unlikely to affect the dispatch of wind for some time because it has low or zero variable costs. In addition, a significant amount of existing renewable generation falls below the de minimis limits for being subject to central dispatch. Consequently, it is effectively autonomous; to all intents and purposes enjoying (virtually) physically firm transmission access at present levels of wind connection. However, taking into account wider system costs, such as the start-up requirements for other generation to support variable generation, may have an impact on dispatch pattern of wind leading to it being constrained down more often than otherwise. As wind connections increase, the incidence of wind being dispatched down is expected to rise.

2.1.3 Our views

We agree that firm or non-firm access should not be a consideration in the dispatch decision provided that this does not distort investment incentives or consumption decisions. For example, the treatment of non-firm access under the current arrangements means that the dispatch decision does affect the market schedule.

It is important to note that this principle does not hinder efficient consumption decisions in the short term, or efficient investment decisions or consumption planning in the long term.

In order to comply with European law, the dispatch decision must be made subject to the legal requirement for priority dispatch and access requirements arising from the 2009 Renewables Directive. There is a range of possible interpretations of these requirements, with the key issue being whether or not costs can be taken into account in the provision of priority dispatch. These issues are considered further in the subsequent discussion of the detailed options put forward by the consultation document (see Section 3).

2.2 Principle ii) – infra-marginal rents, required to give investment incentives for generators to construct an efficient generation mix, should be allocated to generating plant that is useful in meeting customer demand, in order that an efficient mix of usable plant is delivered

The consultation document suggests that the allocation of infra-marginal rents should provide appropriate incentives for investment in and closure of generating plant. There is particular concern that the current market design does not appropriately incentivise investment in (as opposed to the operation of) plant. This is because it over-rewards plant in export-constrained zones and under-rewards plant that is constrained on in an import-constrained zone compared to an economic ideal.

The existing treatment of non-firm access in the schedule is based on the implicit assumption that the dispatch of a plant with non-firm access is an indication that there is no export constraint for that plant. The development of plants with non-firm access and low variable costs, such as wind generation, means that they can displace in the dispatch decision more expensive plants with firm access. Therefore, the dispatch decision for such plant currently only reflects whether the plant is behind a plant-specific export constraint as opposed to a collective export constraint.

2.2.1 Implications

Currently, plants that are constrained on to meet demand only receive their short-run marginal costs. Therefore, we agree with the statement within the consultation document that there may not be appropriate signals to deliver the most efficient generation mix in the long-term, to the extent that additional investment is required in plants which are frequently required to generate outside the schedule (other than the BNE peaker which is the basis for capacity payments). The options set out in the document seek to address the allocation of infra-marginal rents by introducing additional factors into the market schedule. This includes reserve and locational elements, by placing limits on the scheduling of non-firm plant.

2.2.2 Implications for wind

Typically registered as either variable price taker or autonomous, wind generation cannot effectively be constrained on. Therefore, under the application of this proposed principle, it would not benefit from any increase in the rewards given to the type of generation that is constrained on in import-constrained areas. Similarly, it is (generally) not constrained down in export-constrained zones (at present). In this regard, we agree that there does not need to be a specific definition of 'curtailment' (as discussed on page 29 and 30 of the consultation document). This avoids the creation of a definition which could later be used to the detriment of wind generation.

2.2.3 Our views

Although in principle we would agree that infra-marginal rents should be allocated to generating units that are of value to the real-time operation of the system, account also needs to be taken of:

- the high level SEM principles of a uniform SMP and separation of transmission constraints from the market schedule;
- priority dispatch legislation; and
- ensuring that there is no impediment to overall Irish and Northern Irish energy policy.

If there is a systematic requirement for additional revenue for flexible plants (e.g. for the provision of spinning reserve), then it would be best addressed through the creation of a specific market-based revenue stream rather than distorting the existing market payments for energy (SMP) and capacity. This could be through a static payment scheme (e.g. ancillary services contracts) or a more dynamic reserve pricing mechanism.

[This page is intentionally blank]

3. REVIEW OF OPTIONS PUT FORWARD IN DOCUMENT

The RAs set out a list of proposals for comment on pages 60-62 of the consultation document. In this section, we describe the implications, particularly for wind, of the detailed options proposed in that list (as opposed to the principles discussed in Section 2). We then provide our views on the advantages and disadvantages of the proposal. For ease of reference, the options are addressed in the order listed in the document.

3.1 Provision of information by TSO and asset owners

Proposal: 'The TSOs and asset owners should continue to make available information relating to:

(a) their understanding of what changes to the scheduling and dispatch of generation are being contemplated in light of the increasing level of renewable generation on the system, including where there may be technical limitations on the quantity of certain types of plant that can be accommodated on the system; and

(b) their view of how technical issues (for example system inertia, fault levels etc.) will be resolved.'

3.1.1 Implications

The impact of the inclusion of additional technical constraints in the dispatch or scheduling decision will vary across generators, as to whether they appear in the schedule more or less often and whether they are dispatched away from their MSQ. Any impact on the dispatch decision would need to be consistent with the requirements set out in the Renewables Directive.

This proposal should provide greater transparency on the decision making process with respect to technical network issues. The impact on certainty for generators is unclear as greater information may be offset by the sense that the arrangements are under continual review.

3.1.2 Implications for wind generation

The intermittent nature of wind plant means that they are inherently associated with the type of technical considerations discussed in the proposal. Therefore, wind generators will need to be watchful that technical issues are not used to build a barrier to the greater deployment of renewable generation, and that appropriate governance is placed on the TSO in making decisions on scheduling and dispatch.

3.1.3 Our view

We recognise that this proposal should provide greater transparency, which is one of the principles of the TSC. In accordance with this, any limitations on output from certain types of generation should be based on clear, non-discriminatory criteria that reflect its impact on the system, rather than any blanket application by technology type.

We note that the Renewables Directive sets out a requirement to address any operational obstacles to priority dispatch. Therefore, the TSO and asset owners would also need to set out information on how they were going to address any technical issues that resulted in lower dispatch of renewable generation than otherwise would be the case. This would include demonstrating that they had considered the full range of technical management issues, including the role of the demand-side and new network technology.

3.2 Compliance with Grid Code

Proposal: 'In relation to the Grid Code;

(a) the current initiative from the TSOs to place additional emphasis on enforcing existing Grid Code obligations on incumbent and new generating units should continue; and

(b) the TSOs should also keep the Grid Code under review in order to ensure that future generation portfolios continue to support the satisfactory operation of the system.'

3.2.1 Implications

This would provide greater certainty to SEM parties in terms of the enforcement regime for existing obligations.

3.2.2 Implications for wind generation

The impact on wind generation is uncertain. To the extent that such plants are required to comply with Grid Code rules that they do not currently adhere to, this will presumably increase their costs. However, if the enforcement process improves the stability of the grid, this may allow increased accommodation of renewable generation.

3.2.3 Our views

We recognise that the Grid Code will continue to evolve in line with the needs of the system and more flexibility may be required in future. The approach of the TSOs to the enforcement of compliance with the Grid Code needs to balance a number of key TSC principles, including transparency and no undue discrimination, within a regulatory framework which includes issues such as proportionality.

A simple implementation of this option may preclude opportunities for generators to effectively 'trade obligations' under some form of TSO overview. This trading would require a clear framework for the allocation of rights and liabilities to the different parties involved in such a trade, and could reduce overall costs of compliance.

Therefore, the TSO needs to be mindful of the benefits of removing Grid Code obligations where they appear to be redundant and encouraging more flexible approaches to compliance that are consistent with maintaining the security of the overall system. This could include a cost-reflective fee for derogation, sharing of obligations or trading of obligations, and involvement of the demand-side.

3.3 Limitation of access to the market schedule for plant situated behind export constraints

Proposal: 'The RAs would welcome views on how access to the market schedule for plant situated behind export constraints should be limited and on the options described in this Section 4.5. Respondents are also invited to propose alternative options to those presented in the above section.'

The consultation document puts forward three options for the treatment of access rights for plant behind an export constraint. These options would also have implications for plants that are not behind an export constraint.

We note that none of these options includes locational pricing. We consider that a complete move to nodal or zonal pricing for generation and demand would in many ways be more efficient in the allocation of infra-marginal rent and prices to consumers than a single uniform price market, especially in the future world in which transmission constraints will be contingent on wind levels and with the possibility of smart metering, smart grids and smart consumption decisions. However, we consider that this approach is precluded in the medium term under the current set of regulatory principles and the process which followed the collapse of the previous MAE market design for Ireland. While we believe that the application of locational pricing should be kept under review for the longer term, we consider that it is premature to consider this option so soon after the introduction of the SEM, simply in the interests of sound regulatory practice.

Option 1 introduces transmission constraints into the market schedule but retains a uniform national SMP. For plants with non-firm access, Option 2 breaks the link between the dispatch decision and inclusion in the market schedule. Plants with non-firm access that are dispatched on a least-cost basis would receive their bid price rather than the SMP, and hence would not capture any of the infra-marginal rent associated with being scheduled. Option 3 mirrors Option 2 with respect to non-firm plant behind a binding export constraint but leaves the arrangements unchanged for non-firm plant not behind a binding export constraint, i.e. permitting non-firm plants to be included in the schedule in areas in which constraints are not binding.

3.4 Option 1 – export constraints added to the market schedule

3.4.1 Implications

This effectively transfers the infra-marginal rent from plant that is constrained down behind an export constraint to plant that is constrained on behind an import constraint. All access effectively becomes non-firm because plants with existing ‘firm access’ are no longer guaranteed access to an unconstrained schedule.

By introducing transmission constraints into the schedule, this option will reduce the difference between the dispatch pattern and the market schedule. The SMP will tend to be higher in this (partially) constrained schedule than in an unconstrained schedule (as currently used). This would lead to an increase in the overall costs to consumers.

3.4.2 Implications for wind

This option may be attractive for wind generation. Even with the application of ‘qualified’ priority dispatch (discussed in Section 3.8 below), wind will not frequently be constrained down (assuming that there is not wind on wind competition within an export constrained zone). This means that it will for the most part receive SMP even with non-firm access, as at present. The SMP may also be marginally higher, which will increase the infra-marginal rent collected by wind even in the export-constrained zone. The position for wind generation compares favourably to conventional generation in the export-constrained areas, which will tend to be scheduled less and therefore receive less infra-marginal rent compared with the status quo.

3.4.3 Our views

This option addresses the concerns raised in the document about the economic efficiency of the allocation of infra-marginal rent and should provide more appropriate locational investment signals than the status quo, particularly for conventional generation. Although this option departs from the SEM principle of an unconstrained schedule, it does retain the concept of a nationally uniform SMP.

However, it effectively removes the concept of firm access rights, since access to the schedule within each area is effectively determined in price order without consideration of firm access. There may be legal considerations to this since firm access is embedded within most existing generators' connection agreements; the degree of regulatory risk introduced by the inclusion of such an option is in our view unwarranted.

3.5 Option 2: infra-marginal rents only allocated to generators with firm access

3.5.1 Implications

All non-firm generators would only receive a bid price (for their actual generation), irrespective of whether or not they operate or how their bid prices compare with those of other generators. By removing non-firm plant from the schedule in all circumstances, this option will at times result in more expensive plant appearing in the schedule which will lead to higher SMP than at present. It also leads to a transfer of infra-marginal rent from plant with non-firm access that is constrained on to plants that now appear in the schedule but are not dispatched on cost grounds. This will disincentivise investment in any generation until firm access is available (although presumably capacity payments would continue to apply to non-firm generation).

3.5.2 Implications for wind

The constraint payment and uninstructed imbalance rules for variable price taker (VPT) and autonomous generators would need to be amended to achieve the intent of this option, since there is no concept of constrained-on payments for such generation. We assume that the effective bid price for wind and therefore its price received when constrained on would be zero or below. This would clearly be commercially disastrous for existing wind plant with non-firm access. However, some of the impact may be mitigated by capacity payments and by the REFIT mechanism which effectively guarantees them an effective average floor price, and by the NIROC mechanism in Northern Ireland.

In practice, this option could effectively prevent all new wind and other generation in export constrained zones (including peakers) from connecting until such times as grid reinforcement works were completed to allow firm access. There would be a consequent loss of wind generation, compared with what could otherwise have been provided within the limits of the grid. This could put at risk the achievement of the Governments' energy policies, such as the renewable energy target or carbon emissions reductions.

3.5.3 Our views

We would not support this option on economic grounds and believe that it would not be politically acceptable given the renewable energy targets that apply in both the Republic of Ireland and in Northern Ireland and the ongoing need for investment in conventional generation. This option would go against the general desire expressed in the document to keep the market schedule (broadly) in line with dispatch.

It is not clear how this option could be extended to cover autonomous generation given its current treatment in the dispatch framework.

3.6 Option 3 – infra-marginal rents only allocated to non-firm generators when not behind binding export constraint

3.6.1 Implications

Where non-firm generators are not behind binding export constraints, they would appear in the schedule (as now). Where non-firm generators are dispatched but are behind a binding export constraint, they would not appear in the schedule and would only receive a bid price. This provides a much clearer distinction between firm and non-firm access rights than compared with the status quo, when the indication of whether a binding export constraint binds is related to the individual plant rather than a broader constraint.

3.6.2 Implications for wind

As with Option 2, the constraint payment and uninstructed imbalance rules for variable price taker and autonomous generators would need to be amended to achieve the intent of this option, since there is no concept of constrained-on payments for such generation. We assume that the effective bid price for wind and therefore its price received when constrained on would be zero or below.

For non-firm generators in general, this option is preferable to Option 2 as it provides circumstances in which they can obtain infra-marginal rent. However, for existing wind plant behind binding export constraints that are constrained-on, this would clearly be commercially disastrous (notwithstanding the impact of REFIT which guarantees an effective average floor price).

In practice, it would discourage new wind from connecting until grid reinforcement works were completed to allow firm access. There would be a consequent loss of wind generation, compared with what could otherwise have been provided within the limits of the grid. This would put at risk the achievement of the Governments' energy policies (but not to the same extent as Option 2).

3.6.3 Our views

We agree that in principle it may be appropriate to determine the firm access quantity (FAQ) for the non-firm plant according to whether export constraints are binding, rather than by output as at present. This would provide disincentives for such plant to locate behind export constraints and appears to be more consistent with the principles of firm and non-firm access than the status quo.

However, the unfavourable impact on (non-firm) wind revenue and investment means that it may run into significant political opposition.

Of the reform options, Option 3 appears the least inappropriate of the three, and respects existing agreements for firm and non-firm access. (In fact, the relative rights enjoyed by firm access over non-firm will be increased somewhat beyond the status quo – to provide some degree of priority in scheduling, over and above the current financial compensation for being constrained-off.) However:

- Option 3 is likely to be detrimental for wind connecting in areas of transmission constraints compared to the status quo. This is despite the system benefiting from the output of the wind, which will remain as in the status quo (as wind will still be dispatched ahead of thermal generation on cost grounds).

- The adverse impact on the economics of existing wind generation (behind export constraints) will likely discourage investment in new wind projects, at least ahead of the time by which firm access can be provided.
- SMP will on tend to be higher than under the status quo, and the additional cost (to consumers) is unlikely to be efficiently allocated to those specific plants currently constrained on for transmission reasons.
- The implementation cost for Option 3 might also be excessive compared to the actual costs of the transmission constraints themselves.

All-in-all, we consider that the status quo is preferable to the three reform options proposed. Alongside the status quo, incentives need to be put on the TSOs/TAOs to ensure that grid reinforcements are delivered in a timely manner.

3.7 No introduction of 'Deemed Firm Access'

Proposal: 'The RAs propose that 'Deemed Firm Access', whereby FAQ [Firm Access Quantity] or MEC [Maximum Export Capacity] is allocated in advance of the completion of necessary transmission system infrastructure reinforcements, should not be introduced to the SEM'.

3.7.1 Implications

A mechanism for providing 'Deemed Firm Access' would lead to the allocation of firm access by a specified date irrespective of whether or not the necessary transmission system infrastructure reinforcements have been completed. The RAs do not support the introduction of this to the SEM, primarily on the grounds that it would distort the allocation of infra-marginal rents and excessively incentivise investment behind export constraints.

The implication of maintaining the status quo is that any investment in generation capacity could be exposed to the risk of delays in the development of the electricity network, depending on its location. The requirement for major network investment means that the risk could be significantly higher over the next few years.

3.7.2 Implications for wind generation

The introduction of 'Deemed Firm Access' would support investment in renewable generation by providing certainty about the date at which firm access rights would be provided.

3.7.3 Our views

The evaluation of this option in Appendix 5 of the consultation document highlights the limited scope of the assessment criteria. In particular, there is no principle relating to the delivery of national or European energy policy goals, either with respect to supporting renewable deployment or reducing carbon emissions. In addition, there is no consideration of how the network companies could be incentivised to reduce the costs of introducing 'Deemed Firm Access'. The consideration of possible cost and/or risk mitigation options should form part of the assessment of regulatory options.

Deemed firm access could be useful tool to provide security to wind investment decisions. It can also provide an incentive for efficient grid build, if realistic dates are set and appropriate penalties are imposed on grid operators/owners for delays. The ruling out of 'Deemed Firm Access' by the RAs seems to be inconsistent with their objective behind Option 2 for the allocation of access rights. On page 35, the RAs state that under Option

2, '*there may be more pressure from new entrant generators on the transmission and distribution companies to complete reinforcements in a timely manner'.* However, they do not explain how this pressure will incentivise the transmission and distribution companies to complete reinforcements in a timely manner. It may be more appropriate for the RAs to incentivise the network companies to complete reinforcements in a timely manner, which would mitigate some of the costs that they have identified with the introduction of 'Deemed Access'. Ultimately it is the transmission owner and operator that have the ability to influence to the timescales of grid development and so there should be an incentive mechanism on them to ensure that the network is upgraded under reasonable timescales.

We note that a similar review is being conducted into BETTA, and that 'connect and manage' (similar in effect to the RAs' definition of 'deemed firm access') for renewable generation is DECC's preferred option in GB to address a similar issue. This option does not appear to be considered adequately in the Paper. We believe this to be a direct consequence of omitting the delivery of government renewables targets from the assessment criteria. We further note that the status quo for wind generation is in its effect close to 'connect and manage', due to wind's low variable cost or priority dispatch status. This enables it to be dispatched and also to access the market schedule (other than the exception – expected to be rare in the medium term – of non-firm wind that is constrained off).

3.8 Options for priority dispatch

Question – 'The Regulatory Authorities welcome comments from interested parties on the options for priority dispatch, as presented in this Section 4.8. Specifically the RAs seek comments on:

(a) The case for affording absolute priority or qualified priority to plant having priority dispatch;

(b) In the event that qualified priority were to apply, the relative merits of the alternatives posed for the purpose of attaching an effective price or other objective measure for use by the SOs when making dispatch decisions taking account of the proportionality principle;

(c) Whether a distinction is to be drawn between the priority to be applied when making a decision to place a generating unit in the dispatch schedule as distinct from subsequently dispatching that unit away from that level of output in real time; and

(d) The extent to which non-renewable plant (e.g. peat) who are afforded priority dispatch present particular issues which might require that they are treated in an alternative way to renewable generators'.

The RAs are reviewing whether reform is required to the treatment of renewable generation within the SEM because of the need to comply with relevant European provisions, set out in Article 16(2) of the 2009 Renewables Directive which is an absolute legal requirement. However, the interpretation of the requirements is open to legal debate. There is also the prospect that much higher penetration of renewable generation by 2020 may place strain on the existing arrangements.

3.8.1 The case for affording absolute priority or qualified priority to plant having priority dispatch;

There are a number of key components to the priority dispatch and access requirements set out in 16(2) of the 2009 Renewables Directive:

- exemption from all requirements in 16(2) on the grounds of grid reliability and safety;
- guarantee of transportation for electricity from renewable sources;
- priority or guaranteed access;
- renewable generation is to be given priority in the physical dispatch decision made by the TSO (insofar as allowed by operational factors on the national grid); and
- requirement to address any operational obstacles to priority dispatch.

With the respect to the SEM, these requirements must be interpreted with reference to a centrally dispatched Pool-based market in which renewable generators receive Government support that depends on jurisdiction. We recognise the importance of legal advice on the issue of which of these is the correct interpretation; from an economic perspective we believe that a qualified interpretation of priority dispatch is more appropriate than an absolute interpretation.

One qualification that could be placed on the priority access requirements is that it should not be allocated where it would lead to displacement of renewable generation. This more targeted proposal would work through the connection regime rather than dispatch or scheduling. It is consistent with the spirit of the RES Directive and has the advantage of reducing the possibility that there is an increase in system costs without any rise in the level of renewable generation. It lowers the risk identified by the RAs that '*providing infra-marginal rents to generators that cannot be dispatched will not help to meet emissions targets*' (pg 27).

However, our preference is that some bid price should be used in the dispatch and scheduling process for all generators in order to permit the TSO to dispatch on cost grounds. This is discussed further in the next paragraphs.

3.8.2 The relative merits of the alternatives posed for attaching an effective price for use by the SOs when making dispatch decisions

The consultation document presents four options for 'qualified priority dispatch'. These are all based on assigning a price to renewable generation that can be used for dispatch decisions. The main difference between Options 2(a) and 2(c) is whether or not Government support should be included in the derivation of this 'dispatch price'. Option 2(b) seems to be fundamentally the same as Option 2(a) – it seems unlikely that such 'tie-break' situations will arise between renewable and non-renewable generation. The inclusion of subsidies allows government policies to directly influence the dispatch and scheduling price. This could cause a number of complications given the differences between support schemes in the two jurisdictions and the evolution of support schemes over time.

The introduction of Option 2(c) would require the creation of rules to deal with the operation of the REFIT tariff, which effectively provides a minimum guaranteed price for renewables. (The effect of REFIT and the PSO rules on the effective marginal cost for a generator is unstable, depending on whether the annual average revenue is expected to be above or below the guaranteed minimum.) This would encourage the renewable generators to submit a low bid (in line with short-run marginal bidding principles) as they would not be exposed to the consequences of this bid if they were the marginal plant, assuming REFIT were expected to act as a floor. In this case, PFLOOR may be an appropriate minimum bid for price takers. Wind generators would be free to act as price-makers and submit a higher alternative bid.

Notwithstanding the legal opinion on the interpretation of priority access, we propose an option (a variant of option 2d) that price taker generation would be treated both in dispatch and within the schedule as having a bid price equal to PFLOOR. Such generation has the option of self-dispatching down at times when the SMP is expected to be unattractive, and could alternatively be encouraged to register as price maker and set its own bid price.

3.8.3 Distinguishing between priority in the dispatch schedule and priority in dispatching that unit away from that level of output in real time

We note that the 2009 Renewables Directive might – arguably – permit the distinction between priority dispatch and priority in scheduling as it requires priority dispatch but is less clear on the commercial treatment of renewable generation, in particular as to whether access should be financially firm or non-firm. Therefore, it may be possible to distinguish between the dispatch decision and the treatment within the schedule. Any such distinction would need careful justification; if this question is considered in price terms then ideally the same 'price' for renewable generation would be used for both dispatch and scheduling, as for price maker generation, to avoid perverse incentives (including perverse incentives for wind to register as price taker rather than price maker).

The 2009 Renewables Directive sets out requirements for the priority of renewables with respect to physical access to the network (after the completion of local works)[5]. However, the Directive leaves open to interpretation the question of what commercial rights are provided alongside the physical access, i.e. is priority access financially firm or non-firm? This relates to whether or not the renewable plant is compensated for any transmission constraints that mean that it is not possible to transmit its generation. The implications of receiving non-firm access are affected by a number of factors on which the Directive does not set out any firm requirements[6]. These include:

- the potential for renewable on renewable competition behind an export constraint,
- the treatment of non-firm generation in the schedule; and
- the interaction with the REFIT support scheme.

The RAs discuss the relevance of there being a purchaser for the renewable energy output. They state on page 44 of the consultation document that the priority dispatch requirements in the RES Directive mean that '*there is no need for the renewable generation to have a prior purchaser*'. Although this is applicable for the REFIT scheme, it seems irrelevant in a Pool-based system such as the SEM in which generation is centrally dispatched and there is a single market-clearing price.

If renewable generation is given priority with respect to obtaining (financially) firm access, this could be done through the provision of 'Deemed Firm Access' or through being placed at the front of the queue for the allocation of firm access. In the latter case, this reflects the prioritisation of all renewables over all thermal plant with respect to physical access (i.e. connection) rather than in operational timescales (through dispatch or schedule). Effectively the status quo, which gives non-firm generation access to the schedule when it

5 Given the conditions in the Directive, it is not certain that a TSO would have to absolutely prioritise the completion of local works for renewables at the expense of other system developments. However, compliance with the Directive would imply that these works should be given a higher priority than they might otherwise have been,

6 Paragraph 61 of the introduction to the RES Directive states 'However, this does not imply any obligation of Member States to support or to introduce purchase obligations for renewable energy.'

is dispatched, limits differences between priority in dispatch and priority access to the schedule.

3.8.4 The treatment of non-renewable plant (e.g. peat) who are afforded priority dispatch

We agree the need to review the current arrangements with regard to priority dispatch within the SEM. There is currently priority given to designated plants both in the market schedule and in the (re)dispatch of plant by the TSO but without a sound legal basis.

Renewables and peat plants which are dispatchable are allowed to register in the SEM as price takers (wind and run-of-river hydro is Variable, other generation including peat is Predictable), and generation which is not dispatchable is registered as Autonomous or (for generation below 10MW) as negative demand. All of these are price takers from the perspective of the market schedule. This means that their output is effectively netted off demand before the market schedule has been calculated. In contrast, other conventional generators must be registered as price makers. Price taker status effectively circumvents any limitations on their transmission access, effectively giving full (financial) firm access for their entire capacity even if formally under their connection agreement some of this was intended to have non-firm access.

In effect, price taker status provides compensation in the event that the output of the generator is constrained below their desired operating pattern, but not compensation for other foregone benefits (e.g. REFIT support, NIROCs, Levy Exemption Certificates). If such plants choose to register as price makers and submit prices, they receive full financial compensation in the event of transmission constraints. They also get precedence over non-Priority Dispatch plants in the unlikely event of a tie-break.

In addition, when making (re)dispatch decisions, the TSO currently seeks to redispatch plant in the following order:

- price making generation;
- price-taking generation – peat;
- price-taking generation – hydro;
- price-taking generation – wind; and
- autonomous wind.

There are pieces of European legislation that allow the prioritisation of renewable sources (Directive 2001/77/EC) and indigenous fuel sources, such as peat (Directive 2003/54/EC[7]). The first Directive will be repealed by the 2009 Renewables Directive, but there will be no impact on the 2003 Directive with respect to peat.

We are aware of no basis for the existing priority dispatch arrangements, including the definition of Priority Dispatch in the Grid Code, in existing national legislation. Priority dispatch was enabled in the Republic of Ireland through Section 9 (5)(e) of the Electricity Regulation Act 1999, but in 2007 the SEM legislation revoked this part of the Act. There was no such legislation in Northern Ireland. The Electricity Regulation Act however (as in the equivalent legislation in Northern Ireland) does provide that the regulators and their joint body must promote the use of energy from renewable energy sources.

[7] New Internal Market Directive repealing Directive 2003/54/EC

We note that some of the issues in relation to peat are similar to those of renewable generation with significant variable costs of generation (e.g. biomass) and these issues need to be considered in the context of a centrally dispatched market with a single market price. In a self-dispatch system such as BETTA, such plant would only choose to generate when they receive a price above their short-run marginal costs (including subsidy). However, the explicit absence of a price signal from the dispatch decision in a centrally dispatched market, such as the SEM, means that priority dispatch could lead to such plants generating when the system price is below their marginal cost.

For renewable plants, we suggest that such plants should continue to be given the option to obtain:

- ‘quantity certainty’ – the plant is treated as a price taker (assuming that the concept is retained). In these circumstances, the generators are exposed to SMP and should choose not to generate when the forecast SMP was below their SRMC; or
- ‘price certainty’ – the plant waives its right to priority dispatch and is treated as a price maker with the all associated obligations, e.g. submitting a bid based on its own perceived short-run marginal cost.

This is consistent with the 2009 Renewables Directive, which does not imply that renewables should be given certainty in terms of both price and quantity.

It would be for national energy policy to decide if similar treatment should be given to non-renewable sources such as peat. In any case, such generation types would not in our view, under the 2009 Renewables Directive, be able to receive priority treatment over renewables.

Ideally, more generators would be encouraged to submit prices and to avoid arbitrary ‘deemed’ bid prices, at least to the extent that the TSO has the ability to dispatch generation purely on price grounds without having to distinguish between generation which has not submitted a price. If Excessive Generation Events become more frequent and price taker generators fail to voluntarily reduce output at these times, then there would be a case to reduce the value of PFLOOR.

3.9 The treatment of hybrid plant with respect to priority dispatch

Proposal: ‘The RAs propose that the rules applying to hybrid plant should depend upon which of the options for treatment of priority dispatch plant are eventually chosen. The RAs welcome views on how the principles of priority dispatch should be extended to hybrid plant as part of the response to this consultation.’

The options for hybrid plant are linked to the proposed reforms for priority dispatch of renewables.

3.9.1 Implications

At the moment, hybrid plant is not allowed to register as a price taker (i.e. a plant must be 100% eligible for priority dispatch to register as a price taker). This is designed to avoid complicated situations emerging in which part of a plant is treated as a price taker but the remainder of it is a price maker.

If qualified priority dispatch is introduced, that will represent a move away from the strict price taker definition through the introduction of effective bid prices. This would facilitate the recognition of the renewable fraction of the hybrid plant.

3.9.2 Our views

If a qualified dispatch approach is adopted, then it seems appropriate to take into account the renewable fraction of the hybrid plant when calculating an appropriate bid price. This should be done in a consistent manner with fully renewable plant.

Hybrid plant will typically have significant variable costs (unlike wind). Given the importance of the variable costs, it is likely that such plant would register as price makers (like biomass) and effectively waive any right to priority dispatch. Therefore, the status quo would be retained under Option 1 for priority dispatch (i.e. absolute priority dispatch).

However, any such change should be subject to cost benefit analysis (since the implementation complexity could be considerable) and should avoid any perverse incentives for conventional generation to use a small amount of renewable fuel (co-firing or biogas) in order to gain a disproportionate benefit.

3.10 Treatment of Variable Price Takers

Proposal: 'If any of the options in Section 4.5, for allocating infra-marginal rents behind export constraints, is adopted then that option should apply also to Variable Price Takers. If none of these options is adopted and the existing arrangements for allocating infra-marginal rents being export constraints retained, then Variable Price Takers should be limited in the market schedule to the maximum of actual output and FAQ (or MEC when infrastructure works are complete and the VPT becomes fully firm).'

The three options set out in Section 4.5 were the inclusion of constraints in the market schedule, non-firm generation only receiving bid price when constrained on, and non-firm generation only receiving SMP when constrained on if they are not in an export-constrained zone.

3.10.1 Implications

If none of the three options set out in Section 4.5 are implemented , non-firm VPTs will in any event no longer be paid SMP up to their availability, but only up to their actual generation. This addresses an anomaly in the existing market rules, whereby price taker generation is permitted to access the schedule without consideration of firm or non-firm access. This introduces an incentive, at times when output of variable price taker generation is constrained, for the generator to overstate availability (to the extent that this is not provided by an automated system based on wind speed).

The economics of VPTs will thereby become sensitive to the impact of constraints on their operation.

(We believe that the consultation document (page 54) makes a misleading statement that the existing treatment of non-firm variable price taker generation leads to the allocation of infra-marginal rent to more generation than there is demand. This is true in an Excessive Generation Event but not otherwise. The 'Schedule Demand' input to the MSP Software is adjusted for constrained-down quantities by price takers (reference. section N.32 of the TSC). As a consequence the magnitude of the problem is overstated.)

3.10.2 Implications for wind

This is disadvantageous for wind compared with the present treatment of VPTs, although given their priority dispatch status it is not clear whether there will be a material change in overall market outcomes or whether this is a material issue.

Any incentive to game availability (in the energy market) will be removed. On the other hand, the implementation of this option may weaken the pressure on the TAOs to invest in order to relieve transmission constraints.

3.10.3 Our views

This is an acceptable option as it removes a minor anomaly in the existing rules.

3.11 Determination of SMP and MSQs if price-taking generation exceeds demand

Proposal: 'The RAs propose that if Option 2(a) or 2(c) in Section 4.8 is adopted, SMP should be set using the effective bid prices of the marginal Variable Price-Taking generation, rather than at PFLOOR, in the event that the quantity of price-taking generation exceeds demand and reflecting any external subsidies received by the plant (i.e. it should reflect the price used in the dispatch of the plant by the TSOs). PFLOOR would still be used as a lower limit to SMP.'

Proposal: 'The RAs propose that the quantity of generation charged PFLOOR (or paid at the revised SMP set out in proposal 4.11) in the event of an Excessive Generation Event arising from an excess of Price Taking Generation should not exceed System Demand. The MSQs of Price Taking Generation should, in such circumstances be pro-rated down so that the total quantity is equal to System Demand.'

3.11.1 Implications

The concern here is twofold; that in Excessive Generation Events, the level of PFLOOR is lower than the actual marginal cost of generation and that PFLOOR is charged to more generation than total demand.

3.11.2 Implications for wind

The implications of the two proposals is that wind generation will receive a potentially higher price in an Excessive Generation Event but may receive this charge (since the price is negative) payment for a lower number of units (because demand will be adjusted down on a pro-rata basis).

3.11.3 Our views

Our view is that ideally a price should be submitted by sufficient generation to permit the conventional pricing and dispatch decisions to be based on the submitted prices. The existing rules provide Variable generators with a choice of registration as price taker or price maker. Price makers submit their own bid prices (subject to the bidding principles) and price takers (including Autonomous generators) must voluntarily dispatch themselves (e.g. to avoid unattractive prices). If no price has been submitted by a generator then some arbitrary price must be assumed on their behalf, and by definition this will never be appropriate for all generators in the same category.

We consider that the existing PFLOOR mechanism provides the correct incentive as it is self-regulating. If price taker generators are frequently exposed to PFLOOR and would prefer to set their own floor price at a higher level then they have the option of registering as price maker or of self-dispatching down. If the level of PFLOOR is considered generally to be too low then it can be changed in an annual regulatory process.

If (price taker) generators are dispatched assuming one price (negative infinity) and exposed to a different (higher) price then this represents a distortion to the bidding and to the decision over whether to register as price maker or price taker.

This issue may be resolved by using PFLOOR as the price that price takers are assumed to bid into the market (for the purposes of dispatch as well as pricing). This would effectively make them a block (price maker) bid and hence, as now, rationing would still need to occur in an Excessive Generation Event. Generators can always lobby to raise or lower PFLOOR, switch off at times of low (forecast) SMP or switch to being a price maker.

3.12 Rules for de-loading under a tie-break

Proposal: The RAs propose that where tie-break rules are required, de-loading should be instructed on a pro-rata basis in a manner determined by the TSOs.

3.12.1 Our views

Reducing generation on a pro-rata basis seems a broadly reasonable approach to take under such tie break situations; no other approach guarantees equitable treatment given that the circumstances (and support schemes) faced by different generators will be different. This is on the basis that the position is only reached after taking into account all other possible sources of difference, such as safety, priority dispatch, non-firm/firm, and cost. As stated above, our preference is that generators are encouraged to become price makers and submit their own bid prices which would avoid the need for such tie break situations.

It is possible that firm access or non-firm access status would be an acceptable tie-break consideration.

There may be some opportunity for generators to group together and decide for themselves within the group how the de-loading is to be distributed. This merits further consideration.

Contact details

Name	Email	Telephone
Stephen Woodhouse	stephen.woodhouse@poyry.com	+44 1865 812222
James Marshall	james.marshall@poyry.com	+44 1865 812217
Gary Keane	gary.keane@poyry.com	+44 1865 812236

Pöyry Energy Consulting is Europe's leading energy consultancy providing strategic, commercial, regulatory and policy advice to Europe's energy markets. The team of 250 energy specialists, located across 15 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

Pöyry is a global consulting and engineering firm focusing on the energy, forest industry, water and environment, transportation and construction service sectors, with over 7,500 staff operating from offices in 49 countries.

Important

This document contains confidential and commercially sensitive information. Should any requests for disclosure of information contained in this document be received (whether pursuant to; the Freedom of Information Act 2000, the Freedom of Information Act 2003 (Ireland), the Freedom of Information Act 2000 (Northern Ireland), or otherwise), we request that we be notified in writing of the details of such request and that we be consulted and our comments taken into account before any action is taken.

Disclaimer

While Pöyry Energy (Oxford) Ltd ("Pöyry") considers that the information and opinions given in this work are sound, all parties must rely upon their own skill and judgement when making use of it. Pöyry does not make any representation or warranty, expressed or implied, as to the accuracy or completeness of the information contained in this report and assumes no responsibility for the accuracy or completeness of such information. Pöyry will not assume any liability to anyone for any loss or damage arising out of the provision of this report.

Pöyry is a global consulting and engineering firm.

Focusing on the energy, forest industry, water and environment, transportation and construction service sectors, Pöyry employs over 7500 experts globally and has annual net sales of over €821million. Pöyry PLC is listed on NASDAQ OMX in Helsinki.

Pöyry Energy Consulting is Europe's leading energy consultancy providing strategic, commercial, regulatory and policy advice to Europe's energy markets. The team of 250 energy specialists, located across 15 European offices in 12 countries, offers unparalleled expertise in the rapidly changing energy sector.

Pöyry Energy Consulting
King Charles House
Park End Street
Oxford, OX1 1JD
UK

Tel: +44 (0)1865 722660
Fax: +44 (0)1865 722988
www.ilexenergy.com
E-mail: consulting.energy.uk@poyry.com

Pöyry Energy (Oxford) Ltd, Registered in England No. 2573801
King Charles House, Park End Street, Oxford OX1 1JD, UK

www.poyry.com