

Principles of Dispatch and the Design of the Market Schedule in the Trading and Settlement Code - SEM Committee Proposed Position Paper Request and for Further Comment

Synergen's response to SEM-10-060

1 Overview

This paper is Synergen's response to the consultation paper SEM-10-060 published by the RAs on 2nd September 2010. Synergen has no objection to this response being published.

Synergen also supports the NEAI response on SEM-10-60, which has been produced on a collaborative basis between a number of market participants, including Synergen.

In SEM-10-060 the RAs set out their present position on a range of issues that were summarised into eleven specific issues set out in Section 6 of SEM-10-060. These issues reflect the SEMC position, having summarised and commented on responses to SEM-09-073. The RAs also set out in Section 4 of SEM-01-060 the key themes that emerged in response to SEM-09-073.

In summary Synergen has significant concerns regarding the principles of the unconstrained schedule and the allocation of IMR, not only regarding the uncertainty that it would cause for new entry and the likely adverse impact on financing costs, but fundamentally as the removal of firm access for the holders of such rights undermines the balance of rewards within the SEM. Such a re-evaluation of the existing framework should thus only be conducted as part of a thorough assessment of the medium term direction of the SEM, drawing together issues such as regional integration and the balance of rewards within the SEM.

In the remainder of this response:

- Section 2 considers the key themes identified by the RAs in Section 4 of SEM-10-060;
- Section 3 and Section 4 focus on two matters raised by the RAs that Synergen considers to be of primary importance; and
- Section 5 outlines Synergen's views on the other issues covered by SEM-10-060.

2 Key themes identified by the RAs

Synergen understands that the RAs objectives for the SEM are¹:

- protection of the interest of consumers of electricity on the island of Ireland via promotion of effective competition where appropriate;
- security of supply;
- sustainability; and
- regulatory consistency.

In taking forward the consideration of scheduling and dispatch principles the RAs are applying the “decision making paradigm”. Notably, this requires an assessment of any potential changes on the work stream, and other workstreams. Further, decisions need to be both measured against SEM objectives, and targeted only at cases where action is needed.

In Section 4 of the consultation paper² and at the recent workshop, the RAs made it clear, that SEM-10-060 does not propose a decision but rather sets out proposed positions in a number of areas. Thus the RAs’ impact assessments will be undertaken as part of the January 2011 consultation on a proposed decision. With regard to any impact assessment, Synergen does not believe that this should only be taken on the RAs’ preferred outcome, and published as part of any decision paper. Rather we believe that the impact of several options needs to be considered in both an absolute and relative manner. The RAs should publish in advance their approach to such an assessment, and invite comment from interested parties on both the methodology employed, and key assumptions that will underpin the cost benefit analysis.

With regard to the need for a holistic approach, Synergen believes that the RAs should give clear consideration to both the allocation of CPM payments to plant that is not included within the schedule, and the RAs preferred “splitting” option for TLAFs. The second of these linkages is particularly critical as splitting would increase the differences between the scheduling and dispatch of generation, i.e. one decision to change the rules leading to the requirement for another change. Such a decision on TLAFs should only be taken if it passes a two tier test (a) that the approach is consistent with any changes in principle made as a consequence of the issues under consideration in this consultation, and (b) any demonstrated cost benefit and compliance with the RAs decision making paradigm.

Synergen notes the RAs’ comments in response to the concerns of a number of participants regarding regulatory certainty. Whilst it is a truism that the SEM needs to develop and respond to a number of challenges (some of which are externally driven) it is imperative that the SEM maintains a stable commercial environment, allocates risks to those parties best able to manage them, and maintains a pro-competitive

¹ SEM-10-060 Section 3.3.3.

² SEM-10-060 Section 4.1 dealing with the need for a holistic approach. SEM-10-060 Section 4.3 dealing with participant concerns on regulatory uncertainty.

ethos. That means that changes have to be consistent with the market objectives, and that the consistency of the design is maintained. The danger is that change to parts of the Trading and Settlement Code undermines the existing balance of risk and reward that exist in the SEM.

Synergen notes in this context that the SEM is an unusual, if not unique, regime in terms of its treatment of generator risks and rewards. Many of the key parameters within the CPM regime are subject to the determination by the RAs and since market start there have been restrictions imposed on generators via rules within the Bidding Code of Practice. Thus, changes to the risk / reward balance run the risk of increasing commercial risks to classes or individual participants without allowing these risks to be reflected in market prices.

It is Synergen's view that a more commercial market where these risks can be reflected (with regulatory oversight to prevent any abuses) would be in the enduring interest of customers. Consequently, the RAs need to go beyond stating that they recognise the requirement to balance the need for change and the need to develop responses to changing circumstances and provide robust and quantifiable assessments of proposed changes.

3 Principles of the unconstrained schedule

This section focuses a matter set out in SEM-10-060 that Synergen considers to be of primary importance.

SEM-10-060 Section 3.1 describes the RA's view that dispatch is the efficient usage of a portfolio of generation and demand side measures to meet demand, whilst the purpose of the schedule is to allocate IMRs to parties whose bid is less than SMP. Scheduling through this IMR allocation mechanism provides for the portfolio of assets from which efficient dispatch can then take place. The RAs also recognise that access to the schedule is presently reflective of a degree of actual generator conditions (essentially dynamics) and the allocation of transmission capacity.

Synergen accepts that access to the unconstrained schedule has, and should continue to have some limitations placed on it. The RAs position on the relationship between the schedule and dispatch is appears contradictory to us. On the one hand, the abandonment of the concept of firm access would strengthen the relationship between the schedule and dispatch, and reduce constraint costs (albeit we believe with consequences that amount to a net dis-benefit). However, the RAs are planning changes to the relationship of the schedule and demand through the application of a splitting methodology for TLAFs which would increase the differences between the schedule and the dispatch which would change the allocation of IMRs between generators and in the view of the TSOs increase both constraint costs and SMP. This would, all things being equal, directly lead to cost increases to customers.

Synergen notes that the SEMC view in SEM-10-060 is that changes to the relationship between the schedule and dispatch would only be made if the present arrangements were assessed as giving rise to material harm to customers. Our assessment is that the RAs' approach on this issue and for the application of TLAFs in splitting is inconsistent – changes will be made to the relationship between scheduling and dispatch for TLAFs via splitting **unless** there is a case not to, whilst the S&D work stream approach is only to make changes to the relationship between S&D if the existing arrangements cause material harm. Given this approach, Synergen believes that splitting would be inconsistent with the RAs approach as set out in SEM-10-060 and urges the RAs to consider their splitting approach in this context, and only take it forward if it can be demonstrated that the use of the same TLAF approach in both the schedule and the dispatch causes material harm. In short, the approach over assessing the benefits (or material harm) or change needs to be consistently applied across workstreams.

In terms of assessing material harm, Synergen considers that the RAs' original rationale for the unconstrained schedule approach in the SEM is that the competitive benefits of setting price regardless of delivery costs (and indeed the ability to deliver) plus the costs then incurred in physical delivery in dispatch are **lower** than the costs of alternative pricing mechanisms. Consequently, if there are to be any changes to the relationship between the pricing schedule and the dispatch of assets to meet demand, then there needs to be a demonstrated benefit presented by the RAs.

4 Allocation of the IMR behind constraints

This section focuses a matter set out in SEM-10-060 that Synergen considers to be of primary importance.

Conceptually, wholesale electricity markets may treat the concept of firm market access in three ways:

1. No guarantee of access – i.e. generation is non-firm financially;
2. Firm access (or variants thereof to qualifying parties) via the pool / market; or
3. Firm access via arrangements guaranteed by the Network Service Provider (NSP).

The high level design of the SEM adopted the second of these arrangements for generators with firm. The old England and Wales Pool (which had similarities with the SEM) was also based on this approach. Other gross mandatory pools have adopted other arrangements – notably the NEM in Australia that is non-firm. However, the NEM design is based on zones within the market being internally unconstrained (if transmission constraints become binding, new zones would in theory be defined). Constraints, when they bind, between zones leads to SMPs being set on a zonal (not market wide) basis. It is also a feature of the market that generation self-commits and has a right to be dispatch at mingen³. The “non-firm against the market” arrangements in the NEM are thus consistent with other aspects of its overall market design.

If the RAs determine that there is material harm arising from the existing treatment of scheduling and dispatch under the T&SC then the RAs would seek to implement “option 1” – *“to ignore the concept of firm access as it presently operates and model export constraints in the market schedule”*. For ease, our comments assume that the proposal relates to transmission export constraints.

Synergen notes that the TSOs (at the Dundalk seminar) viewed Option 1 as unworkable with their present systems. This related to the ambiguity over the definition of export constraint but also recognised that simplifying assumptions may be required to implement such an approach. To the extent that these simplifications would have material negative impacts on participants, they would be unacceptable to many generators, which would require the transparency and auditability (further comments on this are set out in Section 4.2 of this response). We note that the paper suggests constraints would be likely to be more static than dynamic. However, there is no indication regarding the timeframe over which constraints would be static and clearly weekly could be materially different to static on an annual basis, We are cognisant that interpretation of “export constrained” was described as an implementation issue, and thus presumably open, at the workshop. As this is unclear, our comments assume that the nature of exports constraints may be determined more, or less, frequently.

Synergen’s comments fall into two categories. First we set out our concerns in relation to viability of Option 1 in the context of the SEM design. Second, we discuss

³ Noting that negative pricing arrangements would be employed if there was to be excess generation.

issues associated with the potential implementation of such an approach. For the avoidance of doubt, addressing the practical issues set out would not address the objections in principle that we have to “Option 1”. The practical issues are thus included as supporting reasons why Option 1 should not be pursued – highlighting why it is likely to be infeasible as well as undesirable.

4.1 Market design issues

A number of points of principle related to the SEM design are presented below.

4.1.1 SEM design

In the SEM the mixture of risks and rewards are finely balanced, and broadly aligned with each other. Removal of the concept of financial firmness removes a central (not a peripheral) tenet of the market design and begs questions about its economic integrity. In the absence of financial firmness for the existing holders of such rights, we consider that the SEM arrangements would need to be revised on a root and branch basis. In essence, the SEM design as presently conceived and implemented would be undermined if this option is implemented by the RAs, and alternative arrangements would need to be developed to replace the existing regime.

4.1.2 Regulatory Risk

The SEM arrangements agreed by RAs and Market Participants were explicit regarding the rights of generator participants – notably the firm access rights. These were made clear during the SEM’s development and are set out in the T&SC. It is commercially prejudicial to firm generators to remove such rights – rights that some parties have paid for as firm connection charges. Regarding a new entrant coming into the SEM in advance of the transmission build necessary to afford it firm access the expectation had been of potentially entering on a non-firm basis for a time limited period - and then access becoming firm. Whilst large incumbents may lose firm access - this equally applies to smaller new entrants in successive Gates - a risk that they explained at the workshop.

This regulatory risk impacts the cost of capital and thus is likely to severely prejudice new entry and any re-financing of existing projects. To the extent that increased risks exist, the risk premiums charged by generators would (in a market) increase and be faced by customers. In the SEM, such costs cannot fall within SRMC bidding rules, so would need to be included in the CPM. We have little confidence that such risks would be adequately factored into the CPM - there is thus likely to be a bottom line cost - and this makes the SEM a more risky, and less attractive, place to invest.

4.1.3 The efficient allocation of risk

The removal of IMRs from generators that are firm under the T&SC would leave them exposed to the cost of actions beyond their control (notably network maintenance and operation) should export constraints be dynamic, and thus a closer approximation of dispatch within the schedule.

4.1.4 Consistency of regulatory approach

SEM-10-060 (notably the RAs potential preference for Option 1 regarding the allocation of IMRs) centres on the principle that plant available in dispatch should be

able to access the schedule, and the IMRs that are associated with it. We consider that the underlying principle would thus be that SEM schedule and dispatch would be broadly aligned and, as the RAs note, the schedule is the reward route for IMRs. In this context there is a need for the RAs to re-evaluate the consistency and appropriateness of market splitting in TLAFs – where the opposite outcome would be delivered. For plant where the dispatch quantity exceeds scheduled quantity as a consequence of the splitting of TLAFs (i.e. where actual TLAFs are better than schedule TLAFs plant will be have MWs constrained on – and thus paid at bid. These MWs will thus not be allocated IMR. The converse applies for plant where schedule TLAFs are worse than actual dispatch TLAF values – such plant is constrained off but retains its IMR. This outcome seems both perverse in terms of rewarding efficiency, contrary to the principles espoused in SEM-10-060 and serves to undermine the reward system that underpins the SEM.

4.1.5 Meeting participant objectives

Only two of the twenty-nine respondents to SEM-09-073 supported Option 1, which is the RAs emerging preferred approach of changes to the S&D relationship to be taken forward (contingent on any material harm test). Whilst the RAs need to balance the interests of all stakeholders (notably customers) in formulating regulatory policy, the lack of support for this option is indicative of its flawed conception.

4.1.6 CfD Liquidity

Synergen is concerned that Option 1 would limit the scope for generators to offer CfDs given the uncertainty that would arise in relation to IMR allocation. In short, any volumes that may be scheduled off behind a constraint would not be offered into the contract market as the price/volume exposure for a generator that was physically short of its contracted volumes would most likely be unacceptable – or at the minimum be associated with significant risk premiums.

4.2 Practical concerns

In addition to the issues around the integrity of the market design, its internal consistency, and the financial stability of the SEM outlined in Section 4.1 of this response, there are major questions surrounding the implementation of Option 1.

At the present time, generators primary financial interest is in their schedule position – against which they are financially firm. A move to determine schedule eligibility through the potential to dispatch plant, would require a full codification of the process adopted.

Synergen believes that, should Option 1 or a variant thereof be implemented, all constraint information feeding into the scheduling and dispatch process will need to be fully auditable. This would be necessary as decisions taken by the TSOs would have differential impacts on participants, and there would thus need to be assurances regarding input data, the model used, and output validation. Regular (daily or weekly) and detailed (half-hour by half-hour) constraint information would be necessary in order for existing or intending market participants to attempt to model their businesses.

In this regard it is also important to understand the extent to which there are deviations from RCUC by the TSOs in relation to dispatch decisions (i.e. the extent to which the RCUC output is a starting point for dispatch decisions not a definitive outcome). The importance of this would depend on the working definition of “export constrained”.

In this context, Synergen believes that the transparency of TSO operations is becoming increasingly important and that there is a strong need for a higher level of transparency regarding the weekly nature of transmission constraints. We believe that the RAs should develop proposals to require the TSOs to publish ex-post constraint data on a weekly basis and provide commentary on differences between the schedule and dispatch outcomes for plant.

4.3 Summary of concerns – Option 1

Synergen believes Option 1 to be fundamentally inappropriate given the market design of the SEM, and the requirements to create an efficient SEM. Further it appears to be incapable of a robust implementation. Our main supporting observations regarding this option are summarised below. Option 1 would:

- Leave the risk of transmission unavailability with generators. This mis-allocates risks to parties that cannot, and do not, control them;
- Increase regulatory risk (and thus Cost of Capital);
- Undermine the principles of the SEM:
 - In the SEM, Bid price = SRMC. The CPM represents the shortfall of a BNE plant in meeting its costs from energy and AS payments. The difference between bid (at cost) and SMP is Infra-Marginal Rent (IMR);
 - IMR is thus a contribution to fixed costs for most generating plant (as the CPM payments are not covering the fixed costs of a peaking plant – i.e. the assumed BNE peaker and are certainly not covering the fixed costs of baseload plant);
 - Removing IMR from plant with firm access could thus undermine plants viability if an export constraint bound as CPM plus lower IMRs may not cover its costs – either as CPM is below economic levels, IMRs are lost as access is no longer firm, or both.
- Reduce volumes available to the CfD market as the risks of contract volume exceeding scheduled volumes would increase; and
- Require that generators were compensated for the loss of such rights (financially) via some other route – potentially from the NSPs.

4.4 Synergen’s preferred approach

In its response to SEM-09-073 Synergen supported Option 2 – the respecting of firm access right and the allocation of IMRs only to parties that enjoy firm access rights. Synergen notes the observations in section 5.2 of SEM-10-060. In the section

setting out the SEM Committee Reasoning and Proposed Position (p29-30) the RAs set out the reasons for some parties supporting Option 2 – and sets out the RAs rationale for preferring Option 1. This amounts to the desirability of Option 1 in incentivising new network delivery and the creation of competition behind constraints for IMRs.

Synergen considers that if there were to be an abandonment of firm access principles, broader changes to the SEM would be required. This could include consideration of trading arrangements more in line with the GB market. Any changes within the context of a gross mandatory Pool would, however, need to reflect the nature of competing plant, and the restrictions based on how plant bids, and operates. In short, existing conventional plant that is required to compete with price taking (subsidised) plant and obliged to bid in SRMC is unable to compete on a level playing field. This gives rise to the risk of the regulatory stranding of existing plant. Synergen is happy to compete on cost with flexibility over its bid, but not to be denied the ability to compete on a full cost basis. Synergen also considers that if firm access arrangements are removed then the BCoP should also be removed to allow generators to bid in such a way as to cover their economic costs.

Synergen requests that the RAs:

1. Reconsider variants of Option 2 (including those where firm access rights are tradeable and thus entities with firm access that should economically exit, or be prepared to access the SEM on a partially firm or non-firm basis); and
2. Consider whether such radical proposals as Option 1 should only be considered in the SEM in the context of a fundamental review of the market arrangements including, at a minimum:
 - The approach to Scheduling and Dispatch, including the question of alternative treatments of TLAFS under the RAs “splitting” option;
 - Moves to greater regional integration as manifested through considerations of ex-ante prices;
 - The ongoing nature of the balance of market rewards between energy, CPM and AS; and
 - Intra-day trading.

5 Other Issues within Section 6 of SEM-10-060

Synergen's views on the other issues set out in Section 6 of SEM-10-060 are presented in the following Sub-Sections.

5.1 Principles underlying least cost dispatch

The RAs' position is that the Transmission System Operators should continue to dispatch the system to minimise production costs of generation, taking into account system security requirements and, as now, not taking account of firmness in the dispatch process. Synergen concurs with this view – noting its views on access to the schedule set out above.

5.2 Priority Dispatch

Synergen favoured Option 2a – essentially preserving the principle of dispatch on the basis of economic merit – this being based on the assumption (held by the RAs at the time that priority dispatch was a “qualified right”). Noting the RA view in the paper that priority dispatch to meet renewable targets does not explicitly allow for cost considerations to impact, but that priority dispatch is subject to system security, Synergen concurs with the SEMC position that there should be further consideration of parameters to ensure that there are some cost bounds placed on the costs of priority dispatch.

Regarding the hierarchy set out on page 39 of SEM-10-060, Synergen concurs with this being the basis under which the TSOs should dispatch plant. Subject to security considerations (and such considerations should be transparent and auditable) Synergen believes that the hierarchy should be strictly rule based – i.e. it should go beyond any TSO subjectivity on the day.

Synergen agrees that it is appropriate to consider “must run” in the context of the Grid Code.

5.3 Hybrid plant and priority dispatch

Synergen concurs with the SEMC position that *“In the context of governing legislation, the SEM Committee considers that there is no legal basis for the provision of priority dispatch for hybrid plant as defined”*.

5.4 Deemed firm access

Synergen agrees with the SEMC position that *“deemed firm access whereby FAQ or MEC is allocated in advance of the completion of necessary transmission system infrastructure reinforcements should not be introduced to the SEM”*.

5.5 Treatment of variable price takers in the market schedule

Synergen concurs with the SEMC position of progressing the development of revised rules to reflect the SEM high level design and to align the treatment of Variable Price Takers (VPTs) with that of Price Makers by limiting their access to the market

schedule to the maximum of actual output and FAQ (or MEC when infrastructure works are complete and the VPT becomes fully firm).

5.6 Grid Code matters and information on technical issues

Synergen is in favour of high levels of transparency in the SEM, both in terms of scheduling, and increasingly of the dispatch process. Central to this are:

- Clear and rule based approaches to be adopted by the TSOs;
- Auditability of outcomes by provision of transmission operational data and constraint information ex post;
- Transparency of future system developments; and
- Transparency of the process,

With regard to the Grid Code, Synergen does not in principle object to the TSOs' role in taking forward Grid Code compliance, but this must be in the context of recognising existing derogations. In terms of increasing Grid Code requirements evolving, Synergen does not believe that this should be a way of developing flexibility on the cheap. In short, if flexibility is required because of the nature of intermittent renewable generation volumes coming onto the system, those costs could, in principle, either be:

- allocated to that tranche of plant (adopting a 'polluter pays' principle adopted for the allocation of reserve and ancillary services (AS) costs, for example – noting that this would be complex to develop and is more of a medium-term option); or
- socialised to customers via AS costs

Increased Grid Code compliance costs are not cost free to generators, and have to be recovered from somewhere – they are not a bottom line cost.

5.7 Tie breaks

Synergen has no specific comments on the SEMC proposals for renewable plant tie breaks in dispatch.

5.8 Determination of SMP when demand is met by price takers

Synergen considers that retaining the PFLOOR regime as a lower bound on SMP to be acceptable (i.e. an annual figure by the Regulatory Authorities following consultation with industry).

5.9 Demand target and excess generation events

Synergen concurs with the SEMC position that *"...the quantity of generation charged PFLOOR 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."*