Response to CRM Consultation

(Schwungrad Energie Ltd.)

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I appreciate the opportunity to input into the design of the new market and welcome the opportunity to respond to the CRM consultation.

The CRM is designed with conventional plant in mind and this is right as most of the capacity is provided by such plant. However other non-conventional plant is also required, for example, dynamic and longer term storage to provide system services and maintain system stability. It is important that such plant is considered in the design of all aspects of the market, not just the system services market. Otherwise there is a danger that risks will be created in some aspect of the market which inadvertently cause serious problems for such plant with the result that it may not be built.

The RO creates such a risk in its current design because it is assumed that all players will be able to receive high energy payments when they have to make difference payments i.e. when the reference price is above the strike price. This works for a conventional plant which is dispatched on the basis of its bid price and so, if it is available, it will be running (or at least in the market schedule) and receiving energy payments when the reference price is high. (In practice this depends on the detailed design of the reference price but this is the principle behind the design and it does incentivise such plant to be available at times of system stress.) However, it does not work for storage plant which may well not be running at that time for good reason e.g. the stored energy may be even more valuable to the system operator at a later time, say over the peak. For example, Turlough Hill may only have 2 or 3 units running because the NCC wants to keep sufficient water to run all units over the peak. Yet the remaining units would be liable for RO difference payments.

Some additional rules are required whereby difference payments do not apply if the plant is available but not running for a good reason, as determined by the TSO. The principle should be that plants are not disadvantaged by the decision of the system operator. This principle already applies in the current energy market whereby the generator is compensated if, for example, it is constrained off.

More detailed comments on individual questions are given below. We have not included questions for which we have no material comment.

2.6.1

Feedback on our minded to position to retain the all-island security standard of 8 hours LoLE.

The standard should be consistent within Ireland and Northern Ireland. It is currently 8hrs in Ireland and 4.7hrs in Northern Ireland. In fact, it should be consistent across Europe and probably will be at some stage, so it would be better to move to 3 hrs now. Having a lower security standard could affect inward industrial investment if the other reasons why Ireland is currently a preferred location (such as low corporate tax rate) no longer applied. EirGrid’s Paper entitled “Options for capacity Adequacy Standard in the I-SEM” indicates that the cost would be at most approx. €19m per annum versus a benefit of between €16m and €35m. This would indicate that at worst there would be a break-even situation and at best a significant net benefit to the Irish electricity consumer.

Feedback on our minded to position to base the capacity requirement for the CRM on a single capacity zone

A single capacity zone is preferred as the complexity of locational pricing is not justified. There is already a locational incentive in TUoS in a way in which it can be modified or sharpened over time as the requirement for capacity in certain locations changes.

3.10.1

The approach to setting the Reliability Option Strike Price:

a. *Should we adopt the "floating" Strike Price approach, which is indexed to the spot oil or gas price?*

Yes this helps to achieve the objective that the SP should be set sufficiently high that difference payments are only made when all available capacity is required. Otherwise the SP could go out of date very quickly and generators would be exposed to difference payments even though they were not called to run.

b. *How do we choose the reference unit? Should it be based on actual plant on the system or a hypothetical best new entrant (BNE) peaking unit as currently used for setting the Annual Capacity Payment Sum?*

Using the BNE would be preferable as it gives some exit signal for old inefficient generation plant. Additionally the electricity market is familiar with the BNE approach and will provide an adequate framework without added further complexity to the process.

c. *Should we grandfather this reference unit where a multi-year RO is sold by new capacity?*

Although this adds some complexity, it brings greater certainty for new entrants and would be a better solution in this regard. Where new entrants/new technologies win longer term contracts there is a risk for investors if nameplate capacity has be encontracted for the full duration of the longer term contract. It would be preferable if the plant had the option to make small step reductions in its contracted capacity as the years progressed, if it wished to do so; this might well be the optimum solution for both investors and electricity consumers.

d. *The choice of market reference price options from amongst the options presented and consistency with key objectives.*

This is a critical issue. If it is not designed correctly generators will be at a high risk of having to pay RO difference payments which they are not getting from the energy market. This risk is minimized under Option 4, whether blended price or split market price and the additional complexity would be worthwhile. There are particular issues for non-conventional plant which are highlighted at the start of our response.

e. The requirement for, and design of additional performance incentives,

As discussed at the start of this response, the RO does not work well with certain types of plants such as storage. The first preference would be to find a modification which solves the problem outlined above. However, if such a solution cannot be found or is too complex an alternative incentive to the RO should be considered.

4.12.1

The options for eligibility of demand side and storage providers

The starting point should be that any plant which has a capacity value should be eligible

Do you have a view on the technology vs plant specific approaches to de-rating?

A plant specific approach should be taken to de-rating as the capacity value could vary significantly across a particular plant type. It would also provide an incentive for a plant to find innovative means of increasing its capacity value. A simple example would be a wind generator with energy storage would have a higher value to the system operator in terms of capacity than one without any storage

5.8.1

Whether the Supplier credit cover arrangements for the I-SEM CRM should be broadly similar to those under the SEM, and whether / what credit cover arrangement should be introduced for capacity providers.

All revenues and costs, including capacity, energy and system services should be considered together as a single sum in calculating credit cover. Additionally, credit cover should be calculated on a net basis as some plant may be both significant importers and exporters (such as storage plant) so a net calculation should be basis for determining credit cover. There is a further 'net' point to be taken into account namely that 'exporters' will have earned difference payments which they must pay back and also failure to earn difference payments which they must pay back. These also should be netted off in determining credit cover requirements.

Whether the costs of exchange rate variations (arising from differences in the €/£ exchange rate at the time capacity is procured and its subsequent delivery) should be borne by capacity providers or mutualised across the market.

This should be mutualized across the market as it is not the sole responsibility of generators

6.8.1

Which options for contractual arrangements are the most appropriate as assessed against the listed criteria?

A contract based system rather than a rules based system would be preferable as it brings more certainty thereby reducing funding costs. The customer ultimately benefits from the reduced risk and hence lower cost. The SEMC may consider that contracts under a contracts based system (in contrast to a rules based approach) are more difficult to alter. However, as the percentage of longer term contracts (for new entrants/technologies) is not likely to be a significant percentage of the overall RO contracts – probably less than 25% - then the risk to the electricity customer in this regard is limited, AND is probably more than offset by thelower investor risk which results in lower electricity costs.