The Innovation Centre
Northern Ireland Science Park
Queen's Road
Belfast
BT3 9DT

T 028 9073 7751
F 028 9073 7752
E info@ipower.uk.com
W www.ipower.uk.com

Jean-Pierre Miura
Utility Regulator
Queen's House
14 Queen Street
Belfast BT1 6ED

July 25th 2014

Dear Jean-Pierre,

iPower Response to I-SEM Draft Decision Paper SEM-14-045

Introduction

1. iPower welcome the opportunity to respond to the I-SEM Draft Decision Paper SEM-14-045.
2. We find it difficult to comment on such a draft decision paper because it only outlines the way in which the market will work under the I-SEM. By the time the detail of the market becomes available, there will be a commitment to proceed with the generic approach that has been selected. Even if some very significant issues arise during the development of the detail, there is unlikely to be any opportunity to reconsider any of the alternate approaches given the very tight programme for implementation. This carries with it the risk that the resulting I-SEM is not a good solution and may not be in the best interest of the end consumers or the market participants. Our preference would be to have more detail on all of the options being considered before deciding on either the energy or capacity market approaches, so that a more informed choice can be made.
3. One specific area about which we are gravely concerned is the RAs proposal to throw out the existing CPM in favour of a Reliability Option approach. One thing that we recall as hearing many times along the way from the RAs is that there was much good about the SEM and that they were committed to building on the strengths of the SEM. We are shocked and dismayed that the RAs have abandoned this commitment on the one aspect of the SEM on which there has been near universal consensus – this is the CPM. We understand that compliance with the EUTM is a requirement of the new market but we are wholly unconvinced that it is necessary to make such radical change and in effect throw the baby out with the bathwater.

4. The HLD fundamentals that applied to the SEM have not radically changed therefore the expectation is that the solution which emerged for the SEM in 2007 should not be radically different for this market revision. As a market participant from the very start of the SEM we are very concerned that all that has been good about the SEM is being cast aside in favour of a design that has no strong international basis and using the EUPHEMIA engine in a way that it has not

hitherto been tried and tested. We also note from the I-SEM workshop on June 17th that the RAs strongly advised that it be unlikely that there would be changes to the draft decision without supporting evidence. We would equally suggest that there is a complete lack of supporting evidence from the RAs to substantiate their proposed radical move away from an excellent tried and tested market system that is currently the SEM.

5. iPower have effectively been to the fore in the development of the Demand Side Capacity market in the SEM since its inception. We feel that key aspects are the need to maintain a non-complex, stable, reliable, non-volatile, simple no fuss environment. We believe the introduction of an RO approach will bring a level of complexity that will have a highly de-stabilising impact on the DSC market which could end the present opportunity for demand side to utilise their own capacity in their own market. This at a time when much work has been done and much work ongoing in the DSC market. It is ironic that the RAs would unintentionally propose an approach that is unfair, inequitable and discriminatory against a section of the market that is just starting to flourish when in fact one of their objectives is to permit and encourage such markets to flourish.

6. The capacity market and potentially the energy market, will require significantly more effort and resource by the market participants than the current SEM. This will disproportionately affect the smaller players such as DSUs and AGUs, who do not have the level of resources available to carry out all of the necessary assessments compared to the larger participants. This is in essence a barrier to entry that discriminates against the smaller participants, such as DSUs and AGUs.

Energy Market

7. There is no detail on the way in which the bidding process will work. Currently we submit a single daily bid for availability and price, where the price includes separate marginal, start and no load components. The intention is to use a new algorithm, EUPHEMIA, to dispatch and price the unconstrained day ahead schedule. This only uses a single price in which participants have to include marginal, start and no load costs. Participants will therefore have to take their start and no load costs and spread them over the expected dispatch level and time. To do this efficiently will require all players to use their own dispatch systems to mimic the EUPHEMIA algorithm to develop their most effective bid price. While this may be feasible for the larger participants in the market, it will most definitely impose an undue and discriminatory burden on the smaller players and so put them at a significant disadvantage.

8. It is also not clear whether there will be regulations governing the bid price of participants, as in the current SEM. If the bid price is permitted to include a scarcity premium during times of expected high demand, and with the reliability option as the CRM this would become essential, then prices would need to be variable across the trading day to allow participants to recover sufficient income to provide a reasonable return on their investment. This would be particularly important for those who were not successful in the reliability option auction in the CRM. This again imposes a higher level of resource requirement on all participants, which will disproportionately affect the smaller players such as AGUs and DSUs.

9. It is not clear whether Capacity Providers who do not have ROs will be permitted to participate in the energy market and if they will be subject to some form of pricing regulations within a BCoP type instrument. If so it will be essential that some form of bid price control is implemented because such a price is likely to exceed the strike price very significantly and cause excessive re-payment penalties for those generators participating through the use of ROs.

10. It is not clear what price will be used to determine the reference price in any contract, bilateral, central clearing or the capacity market mechanism – day ahead would be normal. In which case, the unconstrained run on which the dispatch and prices are based, must contain the best estimate of all participants availability and prices. Otherwise the system will have dispatch schedules and prices that are suboptimal. Mandatory participation would be the best approach but may not be feasible in practice for all participants, such as variable generators. Without mandatory participation, there would be significant opportunities for major participants to manipulate the prices in the day ahead market. As a minimum, all major participants should have a mandatory requirement to participate in the DAM, with best endeavours imposed on the smaller players and those with variable generation.

11. The intention is to have bidding in the market by unit with exceptions made for some participants to use portfolio bidding. In paragraph 6.4.35, it states that "the SEM Committee sees merit in allowing the continuation of portfolio bidding for aggregated generator units and for demand side units". However, elsewhere in Decision 1(IV) on page 56, its states "Unit-based participation for generation in general, with (gross portfolio) aggregation arrangements for DSU, demand and (some) variable renewable generation". For the avoidance of doubt or confusion it must be made explicit that both DSUs and AGUs fall within this group for the purposes of portfolio bidding. The alternative is to simply maintain the current TSC definitions of a DSU and AGU as "Generating Units under the Code". In this way both DSU and AGU will continue to fall within the category of "unit bidding"

Capacity Price Mechanism

12. iPower is fully supportive of the view that the I-SEM should include a specific CRM. However we have already voiced our strong concerns above at the proposition of the RO methodology as the preferred option. The message that came clearly from the RAs was that they wished to retain what was good about the SEM and build upon this. But unfortunately this approach has not been carried through. One of the greatest aspects of the SEM is the CPM methodology with its lack of complexity, simple, fair and equitable qualities which ensured all capacity types were given a fair chance in the market. The selection of the RO option has all the appearance of abandoning a well tried and tested method. Whilst we understand that there are new conditions around the EUTM to be included in the design and that the RAs have concerns around missing money and double payments etc we are not at all convinced that such a radical change is necessary to address these concerns.

13. The choice of a centralised reliability option for the CRM is not the preferred option and is likely in our view to present a number of difficulties for smaller participants, particularly AGUs and DSUs, whose income will be heavily dependent on CRM income.

14. It would appear that the basic design of the CRM is to be an auction of reliability options up to a capacity level determined by an assessment of capacity need of the system. Successful bidders will receive an option fee for the RO offered, where the level of option fee is set by the auction. Our understanding is that a strike price will be set by the RAs and if the reference price in the market goes above this level, then the difference between the reference and strike price will be repaid to the centralised body administering the CRM. The key issues and uncertainties with this approach for iPower are as follows:

15. **Auction Process** – how the auction is to be run is not defined – neither is it clear how such an auction will bring the optimum mix of capacity to the market. Highly efficient and desirable

capacity which happens to be more expensive plant could fail in the RO auction. This would represent a significant departure from the existing CPM which places no barriers on capacity type and is the optimal, fair and non-discriminatory method of providing capacity entry to the market. Also the auction could represent an opportunity for speculators with no intention of building real capacity who will just take their chances that they can re-sell their RO at a profit. We would question how this can be avoided. We would ask for clarity on whether the RAs intent to award the ROs to capacity below the auction clearing price and how this price or option fee will be used within the CRM. The main issue for small players with perhaps a small single unit, is that it is either an in or out opportunity – if their bid is at or below the final option fee level they are in, but if it is above then they are out of the capacity market for the duration of the contract term. To be out for the RO term is very likely to spell the end of participation for that unit on the basis that it could be several years before another opportunity arises. Also, on the basis that the ESB may not have the same commercial or business interests as private generators it is possible that the outturn price from the capacity auction would not be sufficient to sustain a commercial generating business. It will be important for regulatory input in setting a minimum price for example.

16. **Strike Price** – Our understanding is that this will be set by the RAs but the mechanism for setting it has not been defined. It is implied that it could be related to the highest short run marginal cost on the system as it has been in other systems. However, with the energy market proposed which includes the use of a single bid price covering marginal, start up and no load costs, defining the SRMC for the most expensive plant will require some other mechanism. Whatever mechanism is used to set the strike price, it needs to be directly linked to the actual market conditions, so that spikes in fuel prices, particularly oil, do not cause the market price chosen for the reference price to rise above the strike price so that the marginal plant do not cover their costs. In addition, if as indicated the relationship of the strike price to the highest cost plant is some form of mark up, this needs to be adequate to cover the uncertainty that inevitably arises on the part of the bidders. Getting the right relationship and ongoing linkage between the strike price and the market price together with an adequate mark-up will be essential, if as seems likely there is a significant lag between the auction and contract start date. However as mentioned previously it will be important to ensure that participants in the energy market who do not have ROs cannot bid ridiculously high prices thereby causing an excessive repayment penalty during a price excursion above the strike price.

17. **Reference Price** – again how this will be set is not defined. It is hinted that it will be related to the market price eg day ahead or imbalance price – this needs to be clarified. If it is set in this way then the strike price does become a cap on the market prices for those participants with ROs, since it effectively limits the market price to the strike price level for these participants. Only those participants in the market without ROs would not have their prices capped. iPower consider that the reference price should be the appropriate market price with no artificial ex post adjustment.

18. **Repayment in the Event of Reference Exceeding Strike Price** – the paper is not clear on how this will be applied. It is indicated in paragraph 8.4.21 that repayment in these circumstances will apply when the RO is called. However, there is a perception that it applies to all participants with ROs during the period when the reference price exceeds the strike price. iPower does not consider that this is a realistic interpretation. Our understanding is that a Reliability Option is only called if a particular unit is dispatched and fails to run during a strike price excursion event. This

needs to be clarified as does the formula for RO repayment. For an RO to be called, the capacity backing that RO has to be dispatched. In which case if the reference price exceeds the strike price then the difference should be repaid under the terms of the RO contract. However, if the plant has not been dispatched, then by definition the RO associated with it has not been called, and so there can be no liability for the RO holder if the reference price is in excess of the strike price. There is much clarification required around all of this.

19. **Time Lag for RO Contracts** – the paper recognises that there will need to be a time lag of several years to allow new plant to be placed on the same footing as existing plant. This time lag has implications for the setting of the strike price as indicated above and the need for some form of linkage with the market price. For existing conventional plant that are not near the end of their normal life, the time lag is not an issue in terms of level of capacity bid into the auction. However, for aggregated units such as AGUs and DSUs that are in general all being developed over time through the ongoing entry and exit of capacity providers, the time lag presents a problem, as the actual level of capacity that can be offered is uncertain. In theory, if ROs can be traded between market participants, then the AGUs/DSUs should be able to trade out any imbalance in their position. However, this will depend on the liquidity of the RO traded market, which is also an unknown until the CRM has been bedded down with some years of experience. If such trading is not possible it is not clear what the per MW exposure is to being long or short on an RO. This uncertainty in the early years of the CRM will be a substantial risk to DSUs and AGUs and is essentially a discriminatory barrier to this type of capacity.

20. **Duration of RO Contracts** – the paper also recognises that new and existing plant may have different contract lengths for ROs. For conventional generation units this is normal and acceptable. However, for AGUs and DSUs the position is quite different. These aggregated units by definition comprise a large number of small capacity providers in the form of demand reduction or small generators and the aggregator will have to have back to back contracts with these capacity providers and the CRM to keep the risk to its business within acceptable bounds. These contracts would normally be for several years to facilitate the engineering input and keep the administration resource requirement within reasonable limits. Consideration should be given to allowing DSUs and AGUs to be treated as new entrants with a longer contract life.

21. **Secondary RO Market** – with an auction process setting both the option fee and the successful participants and with the time lag of several years between the auction and the contract start date, it is essential that a secondary market is developed for the trading of ROs. Those holding ROs will need to be able to trade if they find themselves long through lower than expected availability of plant or short if they have spare capacity available.

22. **Transition Period** – it is clear that there will be a transition period of several years from the time the new CRM based on reliability options is put into place with the first auction and the start of the new CRM when the ROs get applied in practice. No consideration is given in the paper to this. In our view, the simplest and least cost option to all concerned is to continue with the current CPM until the new CRM starts to operate.

23. **Auction Bid Resource Implications** – the RO approach imposes an additional resource requirement on all participants. The requirement for the bid into the RO auction is the same for all players, large or small. To ensure a successful bid into the auction, all participants will have to review all of their potential income sources and all of their costs several years ahead. In addition, to ensure that they submit a competitive bid, an assessment of the competing capacity suppliers

will need to be undertaken. This will require a significant level of resources of a particular kind to carry out these assessments and to prepare the RO auction bids, perhaps as often as once a year. For the larger players, these resources will be available internally and the marginal cost to them of participating in the auction would be minimal. However for smaller players such as DSUs and AGUs, resources of this kind will almost certainly not be available within their companies and so additional expertise will need to be hired in to carry out the necessary assessments and bid preparation. If this were to happen every year, this would impose a significant additional burden on smaller players that is disproportionate to their size. This amounts to discrimination against smaller participants and so some mechanism needs to be put in place that would allow them to reduce the impact of this additional cost. This could be in the form of longer contracts for the AGUs and DSUs perhaps on a par with new plant.