RWE

BY EMAIL ONLY
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SEM Committee

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9th July 2021

Consultations relating to the Electricity Regulation 2019/943– SEM 21-026 & SEM 21-027

Dear Gina, Dear Gary,

Thank you for providing us with the opportunity to respond to the above consultations. RWE Renewables is one of the world's leading renewable energy companies. RWE Renewables Ireland is operating and developing several renewable projects in Ireland, across a range of renewable energy technologies including onshore wind, offshore wind and battery storage systems.

Last year we responded to the SEM-20-028 consultation (as Innogy Renewables Ireland Ltd), as our response was submitted before Innogy Renewables were transferred to RWE. Our position has not changed since our response last year; however, our concerns are growing with regards to some of the proposals which are being made but without a clear, specified intention to change or update the regulatory frameworks within which these proposals would be introduced.

In our response last year, we were clear that for new renewable Non-Priority Dispatch sites, the application of constraints should be treated as market based-redispatch **but only** if sites are enabled to submit Commercial Offer Data (COD), Technical Offer Data (TOD) and Physical Notifications – as otherwise there could be no means for there to be a market based element. We still agree with that position - however, alongside enabling new non-priority dispatch (NPD) renewable generation assets to be able to submit TOD, COD, & PNs, it is vital that the commercial offer data – particularly simple bid offer data allows the inclusion of opportunity cost (i.e. revenues from RESS or REFIT etc) rather than only allowing decremental bids to reflect the additional fuel costs, given that for wind and solar this would be low or zero.

There is no clarity provided in either the consultation SEM-21-026 or SEM-21-027 on how the Balancing Market Code of Practice (BMCOP) and Trading and Settlement Codes (TSC) would be amended to reflect the policy intent of allowing Commercial Offer Data to be submitted and for complex bid offers to include broader opportunity costs (such as lost financial support / subsidies).

We recommend that the SEMC confirms that changes will be implemented to allow controllable but non-dispatchable renewable generators (the new proposed Category 2 units) to submit bids and offers within the TSC, and that the BMCOP is updated to allow the submission of non-marginal complex bids from Category 2 renewable generators - or allow that only simple bids are required, and that details of the relevant milestones for the delivery of this action are set out as a matter of urgency following this consultation.

Recommendation – Regulators to confirm that as well as changes to the Trading and Settlement Code (to allow renewables to submit TOD, COD and PNs) the BCOP and BMCOP will be altered to allow the submission of non-marginal complex bids (or simple bids only) from these Category 2 renewable assets **and** a date by when this will be completed.

We would also suggest that the System Operators (SOs) urgently provide details as to how the proposals set out in the SEM -21-026 consultation can be accommodated and the cost and timescales associated with the successful delivery of changes to either the EDIL or Wind Dispatch Tool provided, or a new system. This should also include the opportunity (or option) to enable individual sites to submit their own bids and offers and for this information to be used within the scheduling process to ensure real-time decisions can be used to determine the most economic outcomes, whilst ensuring the operation of the system isn't compromised.

We are particularly concerned following comments made at the recent System Operator industry round table on 1st July, which suggested that some of the proposals set out on the SEM-21-026 consultation cannot be implemented, and that the changes which will be required to be delivered to the existing systems could be a "bodge job". Instead, the regulators should require the SOs to consider the updates required to their IT systems which will deliver the changes necessary to implement the requirements of the EU Electricity Regulation (2019/943),

Recommendation – Regulators to set out a fixed date by which time the SOs will provide the necessary industry upgrades required to their market operating system /s – it is insufficient to suggest that only minor changes to the system and market frameworks will facilitate and reflect the changing nature of the SEM as it decarbonises.

Without knowing the outcome of these two specific questions, it is very hard to respond positively to the Regulator's minded to proposals as the proposals clearly have some very significant interdependencies, which haven't yet been decided upon and or implemented. For example, if it will not be possible for the SOs to deliver an IT solution that treats and processes Priority and Non-Priority Dispatch sites differently for constraints but the same for curtailment as per the Regulators' proposals then what will instead be implemented and what would be the impacts (to the changes on definition of dispatch and redispatch for PD and NPD sites).

We recommend that as part of any implementation plan to update or replace the existing SO systems, that a transitional phase is introduced, which would allow smaller generators without Priority Dispatch to participate in the Balancing Market through an aggregator or through the introduction of a Virtual Power Plant (VPP). The SEM faces significant challenges to decarbonise and ensure that all new renewable generation can participate and can provide valuable balancing services, especially new renewable generation which is lower cost and therefore able to provide support to the system at a lower cost to the consumer. This will increase the system's flexibility and diversity – which will both support the

SEM's transition and consumers and generators as more market-based solutions will be delivered – creating additional value opportunities.

Likewise, if all new (NPD) renewable non-dispatchable but controllable generation (Category 2) cannot submit bids which reflect their actual opportunity costs - then it is hard to see how any pricing decisions made regarding constraints could be considered market based as it would in effect just be another "deemed" price.

Finally, it is not possible (other than on a theoretical basis) to determine how the different proposals for compensation would impact the wider market, given that ability for compensation is directly linked to whether the site has firm access or not. Given the previous decisions in Ireland for all ECP2 offers to be non-firm with an ongoing uncertainty for future ECP batches – any consideration of the proposals must be made with the knowledge (or even frameworks) as to how and when new grid connection offers, and agreements will be made "firm". This is particularly important for the development of large, offshore windfarms given their scale and capital investment required.

Recommendation – CRU to confirm when and how the methodology under development by EirGrid for Firm Access will be available and utilised, and how this will impact the potential applicants for the RESS and ORESS scheduled to take place in 2022.

We have set out our comments on the proposals constrained within both consultations as separate submissions.

I can be of any further assistance, please let me or Kate (kate.garth@rwe.com) know.

Best wishes

Peter Lefroy
RWE Renewables Ireland

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RWE Renewables Ireland response to SEM-21-027 Consultation – Treatment of New Renewable Units in the SEM.

Section 2.1 – Treatment in Scheduling and Dispatch

We agree with the SEMC's proposal that new renewable sites (which could previously have been treated as Priority Dispatch) will need to register to participate in the market – and that a new category of controllable (but non-dispatchable) units will need to be created for wind and solar assets. Clarity on when this is likely (or possible) to happen would be very helpful.

We support the expectation that this new category of renewables asset will have to submit TOD, COD and PNs, with the caveat that the Commercial Offer Data submitted must be utilised (based on bids and offers submitted by the developer) rather than being bound by the short run marginal costs, given renewables within this category will tend to have marginal costs of which are either very low or zero.

Whilst we support the call that a revised system design to accommodate the new Category 2 units must be submitted to the Regulators for approval within 3 months of the principles of treatment being published by the SEMC, we are concerned that this does not provide any certainty or timescales for delivery and that therefore the decision as to how new, non-priority dispatch renewable generation will remain unclear [negatively impacting on future investment decisions].

A clear commitment to updating the Balancing Market Code of Practice (BMCOP) so that the rules governing the provision of COD (simple and complex bids) are appropriate for new non-dispatchable (but controllable) renewables is urgently required.

2.2 Treatment in the Balancing Market

As per our original response last year, we agree that new renewable units (controllable but non-dispatchable) if dispatched away from their ex ante market positions for energy balancing reasons should be treated in dispatch on an economic basis (so long as the rules around provision of bids and offers is amended (please see our earlier comments), both in relation to changes to the BMCOP and the related system and process changes that will need to be introduced to deliver this policy proposal.

2.3 Bids and Offers

We do not agree with the RAs position that different rules for Bid-Offer Acceptance or changes to the timing or classification will need to be developed to accommodate new renewable units in the market.

It is imperative that the final decision confirms that changes will be made to ensure that new renewables are able to bid in a price that represents their opportunity cost (including the impact of lost subsidy) rather than retaining the current situation, whereby generators are required to bid on a cost reflective basis that reflects the short run marginal cost of operating a unit, which is inappropriate for variable renewable generators.

The proposed position taken by the regulators with regards to the rules for Bid Offer Acceptance needs to be changed, i.e. there must be a clear commitment to amend the BMCOP in order to enable renewable generators to bid in the actual opportunity cost (including loss of subsidy support), as otherwise, it will not be possible for new renewable generators to submit market based bids and offers, as the costs would {at present] be considered to be zero.

With regards to the proposed decision that renewable generators with the same TOD and COD, would be dispatched down on a pro-rata basis, we would support that decision - if the necessary changes are made to the BMCOP that would allow opportunity cost to be included, as otherwise, all new category 2 renewables generators would likely be pro-rated down and that could therefore not be considered dispatch in economic merit order. It would also not allow a commercial differentiation between generators who have a REFIT or RESS contract.

2.4 Treatment of Redispatch (Constraints)

As per our response last year, we support the proposal that the treatment of constraints for new renewables (i.e., non-priority dispatch sites) would be treated as market-based redispatch; based on the bids and offers – but this will require changes to the TSO systems, and it is currently unclear to us following comments from the 1st July 2021 workshop whether it will be possible [if non-dispatchable PD sites are to be treated as non-market based redispatch] .

2.5 Treatment of Redispatch (Curtailment)

The proposed decision confirms the intention to continue to apply curtailment on a pro rata basis to all non-synchronous units – irrespective of priority dispatch status, and we supported this approach in the 2020 consultation.

As earlier noted, the key issue remains whether the SO's will be able to amend / revise their systems to enable the integrated scheduling system to treat redispatch for constraints and curtailment differently and also with different approaches, given the SO's workshop on 1st July suggested the SEM systems can't deliver this differentiated approach.

We note that the consultation confirms the likelihood that the TSOs ruleset for distinguishing between energy balancing, curtailment, and constraint may require updating, and if that is the case, then this will be consulted upon and a clear plan and pathway to deliver the necessary changes to Codes, systems and processes must be provided.

2.6 Arrangements for Implementation

We recognise and support the RAs current approach of setting out the principle of how new (non-priority dispatch) renewables which are non-dispatchable but controllable will be treated, and we recognise there will be significant changes required to the SOs and Market Operator systems, dispatch tools, Codes etc. It is imperative that the changes are delivered in order for market and operational frameworks to reflect the reality that in future it will be these new Category 2 units which will deliver most of the new generation and that ensuring a market-based approach to enable developers and investors to make rational decisions is vital.

The timescales for an enduring set of arrangements that can be implemented within 36 months of the Decision will be challenging but that must not be used as an excuse for failure to deliver. As per our earlier comment, we strongly recommend that as part of the decision for changes to the system, that the interim step of ensuring aggregators can provide "Virtual Power Plants" to enable smaller new renewables generators (or those wishing to give up their Priority Dispatch Status), are able to actively participate within the market.

RWE Renewables Ireland – response to Consultation on Dispatch, Redispatch and Compensation Pursuant to Regulation (EU) 2019/943

Section 2.1. Definition of Dispatch and Redispatch

We agree with the ***proposed definition of dispatch within the SEM – which relates to the scheduling and dispatch of units to meet the energy requirements of the market***. We note the inherent complexities of identifying dispatch and redispatch separately within the central dispatch system (ex post via flagging and tagging). [We note the separate issue raised for priority dispatch wind and solar sites which can't currently be dispatched for energy balancing purposes], so in the scenario whereby the sum of all priority dispatch generation exceeds total demand within a 5 minute period, those sites cannot be dispatched for energy balancing.

We agree that, if necessary, updates may be required to the definition set out in SEM-13-011.

We agree with the ***proposed definition of redispatch – as relating to deviations from the market schedule for generation for both local and broader system reasons (including constraints, and system wide issues such as curtailment due to the SNSP limit***). We agree that in future there may be additional forms of dispatch and redispatch at the distribution level and any solution proposed / new systems must be future proofed to reduce the need for further modifications to address those circumstances.

With regards to the issue of whether decremental actions taken on priority dispatch units can be considered either dispatch and redispatch or redispatch only: We agree that priority dispatch units should not be able to set the imbalance price. We note the complexity associated with the proposed solutions - and the wider implications of the consultation into the Electricity Balancing Guidelines.

From a principle -based regulatory perspective, we would suggest that decremental actions taken on priority dispatch units which are non-dispatchable should be treated as redispatch only. For dispatchable units with priority dispatch, the option set out in the modification which would replace the bid offer acceptance prices for decremental actions to zero (for imbalance pricing calculations, but not settlement).

Given that later proposals, (in relation to compensation). clearly set out the RAs intention to encourage priority dispatch sites to give up their priority dispatch status, we believe this approach would be consistent with that aim. We do not advocate for the removal of existing grandfathered rights (such as priority dispatch) however, we do not wish to see unnecessary complexities (such as the creation of a new flag and associated processes) if there is a better solution and one which could in future help drive a more market-based approach.

Section 2.2. Definition of Non-Market Based Redispatch

We firmly agree that the application of broader system wide redispatch (such as curtailment) should be treated as non-market based redispatch and (unlike the proposal for constraints) should be prorated across both priority and non-priority dispatch units

As per our response last year, we still agree that **constraints** for priority dispatch sites should be considered as non-market based redispatch, with the deemed decremental prices applied.

As set out in our response last year and with regards to the treatment of new renewables which are controllable but non-dispatchable (new Category 2 assets), we agree with the Regulators proposal that for these non-priority sites, constraints should be treated as a form of market-based redispatch. **BUT** this is on the proviso that those units can submit bid offer acceptances which include the broader opportunity cost (the lost subsidy support).

If that issue isn't addressed, then we do not support the Regulator's approach, as for solar and wind, this would be deemed to be near to or zero (given there are no fuel costs) and it would be an **applied** not market based decremental bid – and therefore could not be treated as market-based redispatch

Section 2.3 – Financial Compensation under Article 13.7

We recognise the strength of feeling demonstrated by many of the respondents and the issues this raises for the regulators, in terms of ensuring that the total cost of compensation borne by consumers is not unjustifiably high.

We also agree that there is an intrinsic value for units which still have priority dispatch (compared to new renewables, which do not), which will be subject to energy balancing and constraint actions before other units with priority dispatch.

Whilst we do not believe the firmness of the site should dictate the level of compensation applied for the non-market based redispatch resulting from curtailment, as the firmness of the connection has no impact on the efficacy of the prorated curtailment. However, we recognise the wording of the Regulation which sets out that only firm sites subject to non-market based redispatch are eligible for compensation.

This does however need a clear definition within the SEM, given that in Ireland (under ECP) connections are all issued on a non-firm basis. The new methodology that EirGrid should devise to ensure a firm connection must be published (swiftly) given the direct impact this could have on implementation of the Regulation.

It is also critical that for all new offshore connections – there is clarity provided as to how the connection offers will be provided and the Firm Access Quantities associated with each connection. This must be clarified before prequalification for the first offshore auction opens, given the potential impact on risk and bid prices.

We do not support the proposal set out by the System Operators – (in effect limiting the level of non-synchronous generation that can be scheduled into the Day Ahead Market), particularly given the proposal within their recent Shaping Our Electricity Future consultation, which still envisages a relatively high level of thermal Minimum Generation remaining a requirement for system operation. We recognise there is a potential issue – and we would be happy to work with regulators, the System Operators and DECC to consider the options and implications of significant changes to the market, as the SEM evolves to operate at 95-100% SNSP.

We support the proposal which would see Priority and Non-Priority dispatch units compensated differently, whereby Priority Dispatch units would be compensated (if firm) up to the level of additional operating costs caused by redispatching.

For Non-Priority (non-synchronous) generation with firm access – compensation would be payable up to the DAM price (at the time they are curtailed). This doesn't appear to include forgone revenues (such as financial supports) which is set out in Article 13.7. The associated lost revenue support must be accounted for to be compliant with the Regulation.

Section 2.4 – Application of Proposals from 1 January 2020

As RWE Renewables Ireland does not yet have firm access at its current operational site and is therefore not impacted, we cannot provide an opinion as to which option is likely to provide the best outcome from an administrative burden and accuracy perspective.