Single Electricity Market
(SEM)

Proposed Decision on Treatment of New Renewable Units in the SEM

SEM-21-027
23 April 2021

EXECUTIVE SUMMARY

This Proposed Decision Paper focuses on the Regulatory Authorities' proposals concerning the treatment of new renewable units in the SEM, considering the feedback received to SEM-20-028. The paper includes a number of minded to positions and principles in order to facilitate new renewable units without priority dispatch to take part in the market like any other unit in line with the requirements of Regulation (EU) 2019/943.

Feedback on these proposals is invited from interested stakeholders, considering the context of the Consultation, SEM-21-026, which has been published along with this paper.

Once a final decision on these principles is made by the SEM Committee, a proposal for the design of a solution will be progressed by the TSOs and SEMO leading to design and implementation as soon as possible, noting the complexity that will be involved in this process. The proposed timelines for implementation are discussed further below.

Categories of units and treatment in scheduling and dispatch

In SEM-20-028, the Regulatory Authorities considered three types of units to which these changes would apply, considering new units that will no longer have priority dispatch pursuant to Article 12 of the Regulation, existing units that choose to forego priority dispatch or changes to priority dispatch status due to significant modifications pursuant to Article 12 (6);

> (1) The first category includes new dispatchable units, which would have previously qualified for priority dispatch, for example Waste to Energy plants, high efficiency CHP, Biomass, Hydro and Hybrid Units (Category 1);
>
> (2) The second category includes non-dispatchable but controllable units which would have previously qualified for priority dispatch, for example solar and wind units (Category 2), which will be required to be treated as dispatchable units under these new arrangements and;
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> (3) The third category includes non-dispatchable non-controllable units, which would have previously qualified for priority dispatch (Category 3).

The Regulatory Authorities propose that no specific changes are required to accommodate units considered dispatchable today without priority dispatch, subject to testing and impact assessment being carried out for such units (Category 1) by the TSOs.

In order to accommodate non-dispatchable units without priority dispatch (Category 2), the Regulatory Authorities are of the view that such units will be required to submit PNs, Commercial and Technical Offer Data and be treated as dispatchable units. The Regulatory Authorities are of the view that no change to the timing of submission of PNs for different units is required at this stage but request that the TSOs and SEMO review any changes that may be required to PNs, COD or TOD from a system perspective.

For non-controllable units (Category 3), the position in this Proposed Decision is that there are few options for treating such units in a manner different to what is applied today, however this represents a small proportion of the total installed capacity, which does not currently take part in the Balancing Market. The RAs do acknowledge however that this represents a significant number of small units.

The Regulatory Authorities request that the TSOs and SEMO host one or more workshops as required to discuss some of the issues raised by market participants in their responses to SEM-20-028 in terms of the systems required to facilitate this treatment, as soon as practicable following publication of this Proposed Decision. A proposal for the system design and approach to accommodate such units should then be submitted to the RAs for approval and implementation within three months of a Decision Paper being published on the principles of treatment being published by the SEM Committee. This Decision Paper will be published in Q3 2021.

Treatment in the Balancing Market

This paper proposes that new units without priority dispatch which are dispatched away from their ex-ante market positions for energy balancing reasons should be considered in dispatch on an economic basis like any other instance of balancing energy, accounting for system security considerations. Such units would be dispatched for balancing energy in merit order with other units and these would be treated as energy actions. ‘Balancing energy’ in the European Union Internal Electricity Market means energy used by Transmission System Operators (TSOs) to perform balancing and provided by the balancing service provider (BSP) and this relates to energy actions in the SEM.

As the Wind Dispatch Tool currently only applies constraints and curtailment to renewable units and does not account for balancing energy, the functionality to accommodate new renewable units will need to account for several bid offer acceptances due to TSO actions on such units.

The Regulatory Authorities are not of the view that there should be any separate merit order for balancing energy for non-priority dispatch renewables based on Article 12(1) of the Regulation which states that *'The dispatching of power-generating facilities and demand response shall be non-discriminatory, transparent and, unless otherwise provided under paragraphs 2 to 6, market based.'*

Treatment of bids and offers

This area of the paper considers the application of bids and offers to such units along with the Balancing Market Principles Code of Practice. The Regulatory Authorities are not of the view that different rules for Bid-Offer Acceptance, or any changes to their timing or classification need to be developed in order to accommodate new renewable units in the market.

In the Regulatory Authorities' view, where new renewable units have the same COD, the optimal approach would be to pro-rate the dispatch down across any units with the same COD and that this should be considered in the TSOs' submission for implementation of the interim and enduring system changes required in line with the principles set out in this Proposed Decision Paper. However, the Regulatory Authorities acknowledge that this treatment should be in line with other non-priority dispatch units.

This Proposed Decision does not include any change to the application or content of the Balancing Market Principles Code of Practice but acknowledges that changes may be required to accommodate different unit types as a result of new renewable units taking part in the market without priority dispatch and the Regulatory Authorities will monitor this area in the coming months.

Treatment of constraints and curtailment

The Regulatory Authorities propose that constraints will be applied to all non-priority dispatch units based on a market-based merit order based on the bids and offers of such units, accounting for operational constraints and system security.

The Regulatory Authorities' preferred approach is that curtailment will continue to be applied on a pro-rata basis where required to all non-synchronous units, regardless of their priority dispatch status. This could involve changes to the TSOs' ruleset for distinguishing between curtailment, constraint and energy balancing for new renewable units and existing priority dispatch units based on the principles outlined in this paper. The TSOs have raised concerns with the continued application of pro-rata curtailment while certain units are considered in an economic merit order for constraints and energy balancing and the difficulties this may present in a co-optimised scheduling and dispatch process. Feedback is invited from interested stakeholders on this issue, which will be considered in the upcoming workshops before a Final Decision is published by the SEM Committee.

The Regulatory Authorities request that as part of this process, the TSOs also submit a revised ruleset to SEM-13-011 with any required changes, which will be consulted on by the Regulatory Authorities.

Timelines for implementation

The Regulatory Authorities propose that following publication of this Proposed Decision;

1. At least one workshop is held by the TSOs and SEMO with interested stakeholders to discuss design requirements for a solution.
2. Within three months of the SEM Committee's Final Decision, a paper is prepared by the TSOs and SEMO setting out the detail of interim and enduring implementation proposals and associated timelines, considering feedback received through workshops with stakeholders.
3. This submission will then be subject to final SEM Committee approval.
4. Any required updates to the TSOs ruleset published in SEM-13-011 are submitted to the SEM Committee for consultation.

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1. Introduction

1.1 Clean Energy Package Background

The Clean Energy for all Europeans package (CEP) consists of eight legislative acts, which were adopted, by the European Parliament and European Council in 2018 and 2019 following Commission proposals in November 2016. This involves a comprehensive update of the EU's energy policy framework aimed at enabling the transition to cleaner energy and facilitating a reduction in greenhouse gas emission levels of 40% by 2030 compared to 1990. The revised Regulation on the internal market for electricity (EU) 2019/943[1] under the CEP seeks to amend aspects of wholesale electricity markets in Europe, enhance integration and progress the transition to renewable energy. Having entered into force in July 2019, the majority of the Articles in the Regulation apply from January 2020.

A high-level review was conducted by the Regulatory Authorities (RAs) in the second half of 2019 to identify the areas of the Regulation, which may require action by the SEM Committee with respect to the all-island SEM. The RAs identified a number of areas for action by the SEM Committee in 2020, along with coordination with relevant Government Departments in Ireland and Northern Ireland, in order to progress implementation of the Regulation. Based on this review, a Roadmap for progressing these six areas in 2020 was outlined by the SEM Committee in an Information Paper published in December 2019[2]. This roadmap was updated in December 2020[3].

Two of the areas identified in the Information Paper relate to Article 12 '*Dispatching of generation and demand response*' and Article 13 '*Redispatching*'. Options for the implementation of these Articles in the SEM were consulted on in SEM-20-028. This Consultation closed on 22 June 2020 and considered a range of issues including the definition of dispatch and redispatch in the SEM, changes to eligibility for priority dispatch under the Regulation and compensation for non-market based redispatch.

Following the Consultation on implementation of Articles 12 and 13 of the Regulation, an Information Note, SEM-20-052, was published which outlined the areas of work that the RAs would be progressing through to Q4 2020. An updated Information Note, SEM-20-089 was

[1] Regulation (EU) 2019/943 on the internal market for electricity.
[2] SEM-19-073 Roadmap to Clean Energy Package Implementation
[3] https://www.semcommittee.com/publications/sem-20-089-updated-roadmap-clean-energy-package-implementation

published which provided updates on work in each of these areas. One of the workstreams identified in the Information Note relates to the treatment of new renewable units in the SEM without priority dispatch and the development of systems to facilitate this. This is the focus of this Proposed Decision Paper.

While it was previously indicated by the RAs that this workstream would be progressed through a further Consultation Paper on the treatment of new renewable units in the SEM, given the alignment between respondents on the high-level principles for the transition to renewable units taking part in the markets without priority dispatch, this Proposed Decision Paper includes a number of minded to positions on the principles of how this should operate. Many responses focused on the systems, which would accommodate this, which has been taken account of in this paper, however in the RAs' view it will be more appropriate for the TSOs, and SEMO to lead on the details of system design to accommodate the principles outlined in this Proposed Decision. The process for this is outlined in Section 2.6. This is presented as a Proposed Decision in order to provide interested stakeholders with an opportunity to comment on the proposals given that these will result in significant changes to the market.

The RAs are requesting as part of this Paper that the TSOs and SEMO organise one or more workshops as required to help inform the design and implementation of these principles in scheduling and dispatch and market systems in order to develop a solution which meets the high-level requirements outlined in this paper, taking on board the views of affected market participants. In the RAs' view, these workshops should help to develop and input to further detail of the solution based on the principles outlined in this paper and required amendments to the Trading and Settlement Code, Grid Codes and Balancing Market Principles Statements as required.

1.2 Purpose of this Proposed Decision Paper

This Proposed Decision Paper focuses on the RAs' proposals concerning the treatment of new renewable units in the SEM, considering the feedback received to SEM-20-028. At a high level, the aim of the proposals outlined in this Proposed Decision are to;

1. Ensure that this aspect of the SEM is compliant with the requirements of applicable EU legislation.

2. Facilitate new renewable units without priority dispatch to take part in the market like any other unit as soon as possible, recognising specific issues raised by respondents regarding the treatment of such units.
3. Ensure a level playing field for all market participants, accounting as far as possible for the different characteristics of different types of units.

The RAs have taken an approach in this paper to define the design requirements for this solution having considered the responses received but recognise that further technical detail will need to be developed in terms of system design and implementation, with the TSOs and SEMO best placed to lead on this. It is important that such a solution can be implemented in a timely manner by the TSOs and SEMO as required. The paper includes a number of minded to positions and principles in the following areas;

1. The treatment of units in scheduling and dispatch, which would, prior to Regulation 2019/943, have been eligible for priority dispatch and the information participants, will be required to submit as part of this process. This includes units, which are categorised today as dispatchable, non-dispatchable but controllable and non-dispatchable but non-controllable.
2. The principles for development of systems to accommodate these arrangements, with a proposal for the detailed design to be progressed by the TSOs and SEMO through at least one industry workshop and a submission to the RAs for approval leading to design and implementation. This should include timelines for implementation.
3. The treatment of such units in the balancing market and in relation to constraints and curtailment, including the RAs' preferred approach of continued pro-rata application of curtailment across all non-synchronous units.
4. The treatment of bids and offers for such units.
5. Proposals concerning timelines for implementation of these arrangements and any interim measures which can be considered to facilitate these changes.

Comments are invited on this Proposed Decision Paper until 02 July 2021 and can be sent to gkelly@cru.ie and Gary.Mccullough@uregni.gov.uk. All non-confidential responses will be published with the SEM Committee's Decision in this area.

2. Feedback Received and Consultation Proposals

2.1 Treatment in Scheduling and Dispatch

Consultation Proposals

SEM-20-028 considered how new units without priority dispatch would be treated in terms of the scheduling and dispatch process, the submission of Physical Notifications (PNs), Technical Offer Data (TOD) and Commercial Offer Data (COD) and the current dispatch systems in place in the SEM including the Wind Dispatch Tool and EDIL. Any such units would not be eligible for priority dispatch in line with the decisions outlined in SEM-20-072.

The RAs considered three types of units to which these changes would apply;

(1) The first category includes new dispatchable units, which would have previously qualified for priority dispatch, for example Waste to Energy plants, high efficiency CHP, Biomass, Hydro and Hybrid Units **(Category 1);**

(2) The second category includes non-dispatchable but controllable units which would have previously qualified for priority dispatch, for example solar and wind units **(Category 2),** which will be required to be treated as dispatchable units under these new arrangements and;

(3) The third category includes non-dispatchable non-controllable units, which would have previously qualified for priority dispatch **(Category 3).**

In the case of Category 1, in the Consultation the RAs proposed that as such dispatchable units are already required to submit PNs, TOD and COD data to the TSOs, this change in priority dispatch eligibility could be facilitated through the current scheduling and dispatch processes in place using the Balancing Market Interface (BMI) and EDIL systems. The main difference for such units would be that the entirety of their volume would be taken as part of the economic merit order and not treated as priority dispatch.

In the case of Category 2, while non-dispatchable but controllable participants with priority dispatch may currently submit PNs representing their forecast production, these are not used in the scheduling and dispatch process at present and current systems automatically set the PN of such units as equal to their availability. In addition, such units do not submit COD and

TOD and are dispatched using the Wind Dispatch Tool. In order to accommodate new units which would have previously qualified for priority dispatch and have been categorised to date as non-dispatchable but controllable, for example solar and wind units, the RAs proposed that they would need to be categorised as dispatchable within the Market and be registered as such. The RAs requested feedback from the TSOs on what system changes are practically required to facilitate the change to such units being considered in the scheduling and dispatch process in the same manner as other volumes in the balancing market in order to be compliant with the Regulation. In addition, it was noted that the treatment of PNs, TOD and COD for such units needs to be considered, both for the purpose of scheduling and dispatch and balancing market settlement. A number of options for interim measures to facilitate this were also considered.

In the case of Category 3 for non-dispatchable and non-controllable units, currently these units cannot submit bids and offers to the TSO in the balancing market, as such units cannot follow a dispatch instruction to a particular level of output from the TSO. The Consultation proposed that such units would continue to have the option to provide a PN to the TSOs for information purposes, but that there were challenges in accommodating any changes to the treatment of such units.

Feedback Received

Category 1 Units

In their response, EirGrid and SONI state that units under Category 1 will register in the SEM as dispatchable generation and the scheduling and dispatch systems will treat these units as a standard dispatchable generator, the same as any other conventional unit in the market. EirGrid and SONI do not foresee changes required to the SEM systems to accommodate this but a detailed impact assessment of market and operational systems would be required in any case.

Aughinish Alumina do not agree with the proposal for units, which are dispatchable but no longer eligible for priority dispatch to be treated like any other units in the scheduling and dispatch process. In their view, if the heat load of high efficiency CHP is not taken into consideration the business case for HECHP may be reduced.

CEWEP agree that as either a priority dispatch or non-priority dispatch plant, they can continue to utilise EDIL. CEWEP members are not directly impacted by the considerations of how other renewable generators should be treated.

Category 2 Units

BGE largely support the RA's proposals on how all dispatchable and non-dispatchable RES units are able to interact in the market in the same way as non-RES units with no priority dispatch do. In terms of Category 2 units, this would entail units being balance responsible and submitting COD, TOD and FPNs, but the discrete MW steps in COD would need to be revised to accommodate these new units.

Bord na Mona are of the view that an important consideration around the submission of COD and TOD for Category 2 units is the accuracy of the PNs for renewable generators. They argue that the TSO should respect submitted PNs for renewable generators, as Market Participants' forecasting methodologies are typically more accurate than the TSO.

Cloosh Valley Wind Farm DAC note that Incremental Offer data cannot be provided by Category 2 units and this needs to be factored into any consideration of how these units can be treated. In addition, the burden for smaller market participants in submitting greater levels of data and operating closer to a 24/7 operations desk must be surveyed and considered as part of the solution (including whether this involves the Wind Dispatch Tool, EDIL, or another solution).

Coillte is of the view that there are issues with using existing systems for new renewables under Category 2. For example, for submission of FPNs, if a renewable generator submits an FPN below its technical availability to produce energy based on the forecast available at the time, it will be dispatched to that level even though the forecast may change. In their view, a better approach would be for FPNs for renewables such as windfarms to reflect their availability much closer to real-time after Gate Closure. In terms of systems, in their view an adjustment to the wind dispatch tool will most likely be required as it would be unreasonable to expect smaller units to implement the manual control and declaration processes of EDIL, including real time availability.

In ElectroRoute's view, Category 2 units should be able to submit FPNs reflecting their intended generation schedule to the TSO to give units the greatest control over their output. This approach should also allow for units to be "inc'd up" using COD submitted by units reflecting their willingness to increase generation, in a similar way to dispatchable units.

Enerco Energy notes that units will be required to submit COD and TOD and respond to dispatch instructions from the system operators, which occurs today in a limited form through the application of constraint and curtailments instructions using the Wind Dispatch Tool. In their view, it is vital that this minimises the impact to market participants, as the use of EDIL would cause significant disruption to participants and the market.

ERG Renewables state that forcing units under Category 2 to submit FPNs on a like-for-like basis with conventional technologies does not account for the different technical capabilities of different energy sources and that this would not reflect the output of these units accurately.

In ESB GT's view at the highest level what is required for the implementation of Regulation 2019-943 is that the principles underlying the current market arrangements be extended to these categories of generation.

Innogy Renewables agree that a new category of non-dispatchable but controllable renewable generators should be created, with any deviation from their traded position being settled at the imbalance price.

In their response, ISEA state that if a generator has to integrate with any materially changed system operation structure, this leads to CAPEX and delivery risk. The second risk is that most renewable generators base their business model on the basis of their deliverable power, being their available power being downward redispatched for constraints and curtailment. For generators without priority dispatch, their ability to achieve a market position will also have to be considered. ISEA also raise the issue of renewable generators having to forecast available power one hour in advance in the forms of a MW set point FPN which may be below their available power. They suggest that one potential solution to this issue is for FPNs being automated for updates closer to real-time post gate-closure.

IWEA and NIRIG recognise that there is no process currently for the Wind Dispatch Tool to accept FPNs and recommend the Wind Dispatch Tool is amended, or a purpose built suitable alternative system is developed, to allow this to happen. FPNs for Category 2 should also be considered in light of Article 6(1) of the Regulation in IWEA and NIRIG's view, which allows for non-discrimination between different market participant types, "*taking account of…the different technical capabilities of generation sources*". IWEA and NIRIG also raise the question of whether units under Category 2 can have an FPN other than their availability respected. In addition, they note that units should not be subject to an information imbalance charge – were it introduced – resulting from a difference in the output of a wind farm forecast by the participant and TSO.

EirGrid and SONI are of the view that units under Category 2, should, where possible, be treated in the market systems as dispatchable and submit COD and PNs. PNs should reflect a unit's market position, while being physically feasible; therefore, if a unit is submitting a PN which is very different to their full availability, they should be run to that PN level (unless for reasons for balancing etc.).

Category 3 Units

Almost all respondents are of the view that Category 3 units are outside the scope of dispatch and redispatch, as they do not receive any control signals from the TSO. On this basis, no changes are required to the treatment of such units.

ESB GT is of the view that units under Category 3 do not have a requirement to respond to instructions from the TSOs and as such cannot be dispatched or redispatched. Therefore, the requirements of Article 12 and 13 do not apply to these units. However, out of market generation is an area that warrants some further consideration. In the SEM, there is a significant volume of out of market de-minimus generation with Grid Code or Distribution Code requirements to be controllable by the SOs. Given the end of priority dispatch there is a question as to what treatment new units in this category should be given.

In terms of Category 3 IWEA and NIRIG are of the view that no change is required to these generators whether they are market participants or not.

In the case of non-dispatchable and non-controllable units, EirGrid and SONI note that the lack of controllability with respect to these units results in few options for approaching them in any manner different from what is applied today. This means that these units cannot provide any COD to the TSOs in the balancing market, as they cannot respond to an instruction to increase or decrease their output. As Grid Code requirements set that units of a minimum size must have control features, this means that units of this type are having less impact and the proposal to continue to treat these units as “autonomous” and being cashed out at the imbalance price for any imbalances with their ex-ante market position is appropriate.

Response and Proposed Decision

In the case of Category 1 units, in the RAs’ view it is clear from the responses received and from further review that no specific changes are required to cater for these units. Any new units in this category which are no longer eligible for priority dispatch, or which are subject to significant modifications pursuant to Article 12(6) and set out in SEM-20-072, would be treated in market systems as standard dispatchable generators. The RAs note that EirGrid and SONI will need to conduct a detailed impact assessment of market and operational systems to ensure such units can be accommodated without system changes to accommodate a larger volume of units.

In the case of Category 2 units, the RAs' view is that new units or units which previously held priority dispatch status (previously categorised as non-dispatchable but controllable priority dispatch units) should become dispatchable units in order to be treated in the same way as other non-priority dispatch units, accounting for their technical characteristics and submit PNs, COD and TOD. This would include new units, which are no longer eligible for priority dispatch, and those, which opt to give up their priority dispatch status. This would involve changes to registration requirements for such units and to systems.

In relation to Category 2, a number of respondents proposed that FPNs for such units should be updated closer to gate closure or automated for updates closer to real-time post gate-closure. Currently in the SEM, participants can update their PNs up to 1 hour before the start of each 30-minute imbalance settlement period, with the last submitted PN becoming the units FPN. The RAs have reviewed the timing of gate closure in other markets and whether there is any distinct treatment for variable renewable units. In the Balancing Settlement Code (BSC) in the GB, gate closure is also 1 hour before the start of the settlement period. Section Q of the BSC deals with the submission of PNs and does not treat any particular unit types differently. In Germany, the market design encourages market participants to balance as close to possible to real time with local 30-minute gate closure times, facilitated by ex-ante redispatching conducted by the TSOs to avoid constraints and enable short gate closure times. A 2019 study on the impact of gate closure times on the efficiency of power systems balancing found that a gate closure time of 1 hour before the imbalance settlement period provides a lower operational cost than alternatives, such as 15 minutes beforehand[4].

Article 24 (2) of the Electricity Balancing Guideline requires that balancing energy gate closure times should be as close as possible to real time and not before the intraday cross-zonal gate closure time. In 2018, ACER adopted a decision on intraday cross zonal gate opening and closure times, deciding that the market should close 60 minutes before the start of the relevant market time unit[5].

The RAs acknowledge that this is an area, which needs to be considered in terms of the overall design of market time frames based on the generation mix and increase share of wind and solar generation based on the need to adjust PNs as forecasts are updated. Gate closure provides the TSOs with time to compare the demand forecast with schedules submitted by

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4 https://www.sciencedirect.com/science/article/abs/pii/S0301421519301223
5 https://www.acer.europa.eu/Media/News/Pages/ACER-adopts-a-decision-on-intraday-cross-zonal-gate-opening-and-closure-time.aspx#:~:text=What%20we%20offer-,ACER%20adopts%20a%20decision%20on%20intraday%20cross,gate%20opening%20and%20closure%20time&text=The%20Agency%20decided%20that%20the,the%20relevant%20market%20time%20unit.

generators. Allowing participants to update PNs closer to real time would improve the accuracy of their forecast availability and PNs, however where the TSO needs to operate closer to real time this may in turn increase costs associated with procuring reserve and providing system security (however with more accurate forecasts imbalances to be managed by the TSOs would be expected to be lower). The RAs are of the view that changes to the timing of PNs specific to Category 2 units should not be made at this time and such units should be treated similarly to other units in this respect.

Under both the BSC and Grid Code in GB, variable and non-variable generation technologies are treated in a broadly similar fashion. Balancing Code 2 under the GB Grid Code deals with post gate closure processes including the physical operation of units and the acceptance of Bids and Offers. Section 2.5.1 notes however that '*Physical Notifications must represent the BM Participant's best estimate of expected input or output of Active Power and shall be prepared in accordance with Good Industry Practice*.' In relation to variable units it states '*in respect only of BM Units (or Generating Units) powered by an Intermittent Power Source, where there is a change in the level of the Intermittent Power Source from that forecast and used to derive the Physical Notification, variations from the Physical Notification prevailing at Gate Closure may, subject to remaining within the Registered Capacity, occur providing that the Physical Notification prevailing at Gate Closure was prepared in accordance with Good Industry Practice'.*

It was also noted in responses that the discrete MW steps in COD may need to be revised in order to accommodate Category 2 units. In the SEM, Generators submit COD that defines the costs at which they are prepared to increase or decrease their output. Simple Bid Offer Data is comprised of Incremental and Decremental Price Quantity Pairs while Complex Bid Offer Data is comprised of Incremental and Decremental Price Quantity Pairs, No Load Costs, Start Up Costs and Shut Down Costs. Ten Price Quantity pairs can be provided in each direction from zero to unit availability, in an Absolute MW Quantity format. A difficulty in the design of COD in general is that true generator costs may not follow a standard structure, for example where incremental costs decrease over a certain output range and increase over a different output range. However, different representations of COD may increase issues associated with solving dispatch and commitment decisions by the TSOs, for example, the optimisation today is limited to monotonically increasing or decreasing PQ pairs. In the GB market, the BSC allows for 10 Bid-Offer Pairs in total and it has not been demonstrated in any responses that the current COD design will not accommodate Category 2 units.

The RAs are of the view that no changes are currently required to the design of PNs, COD or TOD however, as part of this Proposed Decision Paper request that the TSOs and SEMO review any changes that may be required from a system perspective. The application of the BMPCoP to such units is discussed further in Section 2.3.

Many responses in relation to Category 2 units focused on the concern over the application of EDIL as a dispatch mechanism for non-priority dispatch variable generators due to its extremely manual nature which would lead to significant costs for market participants, while noting that the Wind Dispatch Tool was not designed for the purpose being discussed in this paper as it does not have a mechanism to accept FPNs for example. The RAs are of the view that the TSOs are best placed to design the dispatch mechanism for Category 2 units and request that following publication of this paper, a workshop is arranged by the TSOs in order to feed into the design of a solution which attempts to account for the concerns raised by participants in their responses to SEM-20-028. The RAs acknowledge however that there are limitations to what can be accommodated and that it is important that there is a level playing field between different market participants in so far as possible. If new renewable units are to participate in the Balancing Market and be treated like other generators, the RAs are of the view that such units should meet obligations to receive Bid Offer Acceptances. At present, the RAs are of the view that at a minimum, either the WDT or EDIL will require revisions in order to accommodate such units and as proposed by respondents significant system changes may be required, based on the risk of scalability of tools designed for a different set of market rules. Changes may also be expected for market participants as to date many Category 2 units will not have been equipped to accept dispatch instructions.

Category 2 units will also be required to submit and maintain forecast active power (MW) availability with real time updates as information changes, along with real-time availability declarations as set out in SDC1 of the Grid Codes. Real time availability signals for such units are currently provided through the TSOs' Energy Management System as opposed to real time availability declarations in EDIL for other units. The RAs are of the view that this will need to be considered along with the overall system to facilitate interaction of such units with the scheduling and dispatch process.

In the RAs' view, Engineering Tolerances and Tolerance Bands may also need to be considered for Category 2 units for the calculation of Uninstructed Imbalances. MW Tolerance, Engineering Tolerance and System per Unit Regulation Factor parameters are largely based on fundamentals of the power system, such as the average size of the units in the market, the overall size of the market, and the operation of units to meet dispatch instructions. The current SEM value for MW Tolerance is 1 MW and Engineering Tolerance is 1%. This is the percentage tolerance between the Dispatch Quantity under a Dispatch Instruction and Actual Output of a Generator Unit, without accounting for frequency deviations, within which the

Generator Unit is deemed to be operating in accordance with its Dispatch Instruction. If a Generator Unit under or over generates by more than the relevant Tolerance Band, a factor is applied (Premium for Under Generation or Discount for Over Generation) which is used in the calculation of Uninstructed Imbalance charges. The intention of this charge is to incentivise units to match their Dispatch Instructions as close as possible through their actual generation. Discount for Over Generation and Premium for Under Generation can, in principle, be based on the typical cost of replacement generation (in the case of under-generation) and the typical cost saving of displaced generation (in the event of over-generation). Both are currently set at 0.2. The RAs request that either these tolerances or alternatively the Premium and Discount factors applied to these tolerances are considered as part of the annual submission of Operational Parameters under the Trading and Settlement Code based on the characteristics of Category 2 units, acknowledging that system changes might be required to accommodate any different treatment of such units.

From further review of the Eirgrid and SONI Grid Codes and the responses received to the Consultation, there are few options available for addressing Category 3 units in a manner different to what is applied today. This includes units, which are exempt from controllability requirements under the Grid Codes and Distribution Codes, and units, which are less than 5MW. The Grid Codes and Distribution Codes include a definition of Controllable PPMs as those, which connected to the system on, or after 1 April 2005 whose generators comprise a Registered Capacity of 5 MW or more.

Some responses to the consultation noted that out of market de-minimus generation should be considered further however where it has controllability requirements, both in terms of how it is treated and compensated. Where generators are in the market, they are registered as Generator Units under the Trading & Settlement Code with their output sold through the SEM. Out of market generators are included as part of Supplier Units, via Non-Participant Generators, and their output reduces the Supplier Unit's demand to be purchased through the SEM. Contracting market participants are responsible for ensuring that the imbalances of such units are settled. In both Ireland and Northern Ireland, the standard connection agreements have clauses, which require generators to enter into a Supply Agreement with a licensed Supplier. The Supply Agreement ensures that any electricity, which is generated at these sites and passed onto the grid, is accounted for by a licenced Supplier who is registered to participate in the SEM. This process for balance responsibility was outlined in SEM-20-027. The RAs do not consider that such units are subject to redispatch, as they are not moved from a market position within the SEM.

SEM Committee Proposed Decision:

The SEM Committee proposes that no specific changes are required to accommodate dispatchable units without priority dispatch, subject to testing and impact assessment being carried out for such units (Category 1) by the TSOs.

In order to accommodate new units which would have previously qualified for priority dispatch and have been categorised to date as non-dispatchable but controllable (Category 2), the RAs are of the view that such units would be required to register as dispatchable units and submit PNs, COD and TOD in so far as it is applicable to them. The RAs are of the view that no change to the timing of submission of PNs for different units is required at this stage but request that the TSOs and SEMO review any changes that may be required to PNs, COD or TOD from a system perspective. For such Category 2 units, the RAs request that the TSOs and SEMO host one or more workshops as required to discuss some of the issues raised by market participants in their responses to SEM-20-028 in terms of the systems required to facilitate this treatment.

A proposal for system design to accommodate such units should then be submitted to the RAs for approval within three months of a Decision Paper on the principles of treatment being published by the SEM Committee. Proposed timelines for implementation are set out in Section 2.6 and should be addressed as part of this submission.

For non-controllable units, there are few options for treating such units in a manner different to what is applied today, however this represents a set of units, which do not currently take part in the market.

2.2 Treatment in the Balancing Market

Consultation Proposals

The RAs noted in the Consultation that any units no longer eligible for priority dispatch may be subject to energy balancing actions by the TSOs like any other unit in the market. The Balancing Market reflects actions taken by the TSOs to keep the system in balance, reflecting differences between the ex-ante market schedule and actual supply and demand along with congestion management and system security requirements as part of the Integrated

Scheduling Process. Under the Electricity Balancing Guideline, 'balancing energy' means the energy used by the TSOs to perform balancing and provided by a balancing service provider. In the SEM energy balancing services are offered into the Balancing Market by generators, energy storage operators and Demand Side Units.

This section of the Consultation considered options for the treatment of energy balancing actions taken by the TSO in relation to new units, which would have previously qualified for priority dispatch and had been categorised as non-dispatchable but controllable, or Category 2 generators in particular. It was proposed that new generators which are no longer eligible for priority dispatch will be subject to energy balancing actions by the TSOs, will be considered in TSO dispatch tools as part of the economic merit order, and settled like any other instance of balancing energy.

Feedback Received

Many respondents including Bord na Mona, DWTE, ElectroRoute and Innogy Renewables support this interpretation, in line with Article 12(1), which states that the dispatching of power generation facilities and demand response shall be non-discriminatory, transparent and market based. ERG note in their response that other markets such as Sweden and GB offer market-based instruments to allow non-dispatchable but controllable RES producers to participate in balancing markets and voluntarily dispatch down their output.

Coillte is of the view that where new renewables are turned down ahead of Priority Dispatch plant, this must be identified as energy balancing and also settled as such. It is critical, however, given that the TSO will start with FPNs in determining what is an energy or non-energy action in real-time, that this interaction is understood by market participants and can be predicted sufficiently to model for upcoming and future long-term contracts for renewables. In their response, Coillte also raise the concept of Biased Quantities under the Trading and Settlement Code, which adjusts the compensation payable when the TSO dispatches a generator away from its FPN, but the ex-ante traded volume is different to the FPN for that generator. In their view, it is important to know how such a Biased Quantity is allocated between dispatch and redispatch bid/offer acceptances.

In IWEA and NIRIG's view a precise definition of energy balancing is required as new non-priority dispatch renewables will be subject to energy balancing first but share curtailment with legacy priority dispatch plant. When FPNs deviate from ex ante traded positions, they can impact what is considered dispatch (energy actions) or redispatch (constraint/curtailment) in real time activities. IWEA and NIRIG also raise a question of whether there will be any new rules regulating the relationship of FPNs to ex-ante traded positions.

EirGrid and SONI agree with the interpretation that energy balancing of renewable generation should be considered in dispatch economically and settled in a similar manner to any other instance of balancing energy. The TSOs acknowledge that this means that a number of TSO and market systems will need to be modified in order to implement these changes. EirGrid and SONI state that clarity will be required on what is meant by energy balancing applying to these units before priority dispatch units, as it is only currently possible to instruct these units for non-energy reasons of curtailment and constraint. It would need to be clear whether it is intended to mean dispatching the units down in merit order with other units or applying some kind of separate rule to dispatch these units down first before other market-based dispatch down.

Response and Proposed Decision

The majority of respondents to the Consultation agree with the RAs' interpretation that new units without priority dispatch which are dispatched away from their ex-ante market positions for energy balancing reasons should be considered in dispatch on an economic basis like any other instance of balancing energy, subject to system security requirements, but that clarity is needed on this as it is only possible to instruct these types of units in relation to curtailment or constraints at present.

The RAs understand that the Wind Dispatch Tool currently only applies constraints and curtailment to renewable units and does not account for balancing energy. The functionality to accommodate new renewable units will need to account for several bid offer acceptances due to TSO actions on such units. As set out in Section 2.1 of this Proposed Decision Paper, the RAs are of the view that new units without priority dispatch should be treated like any other unit in the market, which would entail units being subject to both energy and non-energy actions. Such units would be dispatched for balancing energy in merit order with other units and these would be treated as energy actions.

The RAs are not of the view that there should be any separate merit order for balancing energy for non-priority dispatch renewables based on Article 12(1) of the Regulation which states that *'The dispatching of power-generating facilities and demand response shall be non-discriminatory, transparent and, unless otherwise provided under paragraphs 2 to 6, market based.'* 'Balancing energy' in the European Union Internal Electricity Market means energy used by Transmission System Operators (TSOs) to perform balancing and provided by the balancing service provider (BSP)[6] and this relates to energy actions in the SEM.

[6] (Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing (further referred to as the Network Code on Electricity Balancing, NC EB or EB GL), Article 2(4)).

Energy actions in the balancing market are actions taken by the TSOs to address an overall imbalance between energy supply and demand. The majority of energy actions taken in the balancing market will take place after gate closure and will be settled on simple bid offer data, where bids and offers are submitted by the market participant and have not been flagged or tagged. These actions occur as part of the overall integrated scheduling process with an ex-post process to identify actions driven primarily for energy or non-energy reasons.

Questions have also been raised by respondents in relation to rules for the relationship between FPNs and ex-ante traded positions for such units. Tolerances in relation to dispatch instructions and Uninstructed Imbalance Charges have been discussed in Section 2.1 and biased quantities are considered here.

A biased quantity is calculated based on any difference between a unit's FPN Quantity and the net ex-ante market trades this is supposed to represent. This results in a difference between a unit's FPN Quantity profile and their Dispatch Quantity profile, which does not reflect deviation from the ex-ante market position in that direction. Because of this, it is not eligible to receive balancing market payments at the Imbalance Settlement Price or Bid Offer Price.

The biased quantity is also used to ensure that wind units do not get Curtailment Payments or Charges, or Discount Component Payments for constraints, when they have not been constrained or curtailed below their ex-ante market traded position. The RAs are not of the view that any changes are needed to the principles of treatment of biased quantities for any units and should continue to be based on the removal of any such quantity from imbalance settlement payment or charge calculations. The RAs understand however, that different approaches to the application of biased quantities for new renewable units will need to be considered within the scope of the detailed design and the TSOs and SEMO should consider these as part of the implementation process.

SEM Committee Proposed Decision:

New units without priority dispatch which are dispatched away from their ex-ante market positions for energy balancing reasons should be considered in dispatch on an economic basis like any other instance of balancing energy.

The principles of treatment of Biased Quantities should not change, but different approaches to the application of biased quantities for new renewable units (Category 2 identified in Section 2.1) will need to be considered within the scope of the detailed design and the TSOs and SEMO should consider these as part of the implementation process.

2.3 Bids and Offers

Consultation Proposals

The Consultation Paper considered the application of bids and offers for renewable units and how this interacts with the current Balancing Market Principles Code of Practice in terms of the components of complex offers and whether these are applicable to renewable generation. It also considered how convergent bid prices might be treated for new renewable units. Feedback was invited in order to consider this area further.

Feedback Received

Bord na Mona state in their response that while the variable costs for a non-controllable unit might be zero, such units have significant capital costs to be recovered. In their view, the rules for bid-offer acceptance require further review based on different classes of generators.

In BGE's view, differing approaches may be applied by units in determination of what are 'opportunity costs' (e.g. between those with and without REFIT) so a ruleset needs to apply to these.

Coillte notes that Article 12 and 13 refers to market-based mechanisms for compensation for dispatch and redispatch. For redispatch in SEM, however, the SEM Committee has applied the BMPCOP (which does not allow inclusion of financial support in the formation of bids and offers). It is Coillte's view that the application of the BMPCOP is restrictive in its interpretation of the opportunity costs faced by zero-cost variable generation.

EirGrid and SONI agree that bids and offers should be applied to variable renewable units in scheduling and dispatch, and settlement, in the same way as other units. EirGrid and SONI envision that the submission of COD and TOD may require regulatory oversight, through mechanisms like the Balancing Market Principles Code of Practice, with the use of complex bids questionable for a variable plant like wind or solar.

ESB GT believes that non-priority renewable generation should have the option to submit two sets of pricing information, simple and complex. The simple pricing information where relevant being potentially imbalance pricing setting and the complex pricing adhering to the principle of opportunity cost and applying where TSO actions are deemed to be non-energy. In their view, the delineation between energy only or non-energy for non-priority renewable generation would require amendments to the Methodology for System Operator and Non-Marginal

Flagging to reflect the system constraints actions against these units would be applied to resolve.

Indaver note in their response that the BMPCOP includes a strict non-subsidised avoided cost formula, which does not distinguish the level of subsidy foregone or the wider costs stemming from non-compliance with licensing conditions or waste policy.

IWEA and NIRIG recommend that the rules for bid-offer acceptance classification require further review, consultation, and impact assessment against different classes of generator, and ultimately appropriate governance of the rules. When several bid-offer acceptances are happening simultaneously, e.g. energy balancing followed by curtailment arising from accommodating conventional must-run generation, it is important that it is clear how the single dispatch down instruction will be classified, if there are to be different rules for compensation for the two different actions (also due to the impact of the classifications on burden sharing of dispatch away from availability).

SSE's interpretation of the consultation is that if a unit that loses priority dispatch it is to be treated as a dispatchable unit. Therefore, it is expected that these units would submit bids and offers like other units. However, as these units currently cannot submit this level of information, it is not known how the dispatchable category will fully impact these units and their bidding behaviour.

Convergent Bid Prices

In situations where bid prices are the same, Coillte's view is that best efforts pro-rata allocation of downwards redispatch or dispatch against the scheduled available generation is the most probable outcome, which would be broadly equivalent to how this is treated in the Day-Ahead Market as per the EUPHEMIA algorithm for trades, which provides a share of the available cleared volume across all similarly priced trades. ESB GT also supports this approach.

Eirgrid and SONI note that currently the approach used for scheduling and dispatching conventional units selects one unit over another when they have the same COD, rather than pro-rating the dispatch down across both. Any change from this would be a relatively large change in the scheduling systems, and therefore would only be possible under longer term developments. If the use of COD as the basis of dispatching these units is intended in the short to medium term, it would need to be on the same basis as current conventional units.

In ElectroRoute's view, there should not be a time period when systems cannot facilitate ranking of decremental bids, otherwise there is market discrimination between certain units within the non-priority category. In the treatment of convergent bid prices, the application of actions on a pro-rata basis is the fairest outcome available.

In ISEA's view, for energy balancing, it is expected that most renewables will have divergent prices as they are not regulated under the BMPCOP, so the issue might not be a severe as presented in the consultation. Nevertheless, tie-break situations will exist and should be managed pro-rata where possible.

Response and Proposed Decision

In terms of the issue of timing and classification of bid offer acceptances for different unit types and the link to rules for compensation highlighted by some respondents, there is a process in place for selection of COD based on the timing of Balancing Market actions taken, the format of COD submitted (whether specific to a Trading Period or using Default COD) and the reason the action was taken (energy vs non energy). Whether an action is taken for energy or non-energy reasons is classified based on the ex-post process of flagging and tagging which will determine whether actions are taken for dispatch or redispatch and the compensation associated with each. Instruction issue times before Gate Closure 2 are based on Complex rather than Simple COD.

Currently, a Balancing Market Principles Code of Practice (BMPCoP) applies to Complex Bid Offer Data as a form of market power mitigation for generators and applies to the settlement of non-energy actions. This requires generators to bid on a cost reflective basis for such actions. Under the BMPCoP, Complex Bid Offer Data reflects the short run marginal cost of operating a unit. Section 4.1.6 of the Balancing Market Principles Code of Practice Decision Paper, SEM-17-048, states that '*The BMPCoP applies to all generating sets and units operating in the I-SEM, whether they hold an RO or not.'* Under this Decision, the BMPCoP will similarly apply to new renewable units in the SEM and this Paper does not propose any changes to its application to any particular unit type.

A number of respondents have noted that this does not take account of broader opportunity costs for new renewable units such as lost financial supports/subsidies or wider costs stemming from non-compliance with licensing conditions or waste policy. It is acknowledged that the market changes outlined in this Proposed Decision may require the BMPCoP to be considered to account for the specific characteristics of new renewable technologies without priority dispatch, including their ability to exercise market power. The RAs are not proposing any changes to the application of the BMPCoP at this time but will keep this under review.

The RAs understand from EirGrid and SONI's response that if no system changes are made, where new renewable units have the same COD, the Market Management System (MMS) as part of the scheduling and dispatch process selects one unit over the other rather than pro-rating dispatch down. The application of such tie-break rules changes for every Real Time Dispatch (RTD) run. In the RAs' view, pro-rata application of the dispatch down across any units with the same COD should be considered in the TSOs' submission for implementation of the interim and enduring system changes required, noting consistency between any approach applied to such units and the current treatment of other units in the market.

SEM Committee Proposed Decision:

The RAs are not of the view that different rules for Bid-Offer Acceptance, or any changes to their timing or classification need to be developed in order to accommodate new renewable units in the market.

In the RAs' view, where new renewable units have the same COD, pro-rata dispatch down across units with the same COD should be considered in the TSOs' submission for implementation of the interim and enduring system changes required, noting consistency of treatment with other units in the market.

This Proposed Decision does not include any change to the application or content of the Balancing Market Code of Practice but acknowledges that changes may be considered in future to accommodate different unit types as a result of new renewable units taking part in the market without priority dispatch.

2.4 Treatment of redispatch (constraints)

Consultation Proposals

The RAs proposed in the Consultation that constraints would be market based for new renewable units and based on the principles for submission of COD and TOD outlined in previous sections.

The RAs also proposed that under Article 13(5)(b) of the Regulation, downward redispatching of electricity produced from renewable energy sources or from high-efficiency cogeneration (i.e. the application of constraints and curtailment) regardless of priority dispatch status, should be minimised in the SEM. Under this interpretation, such units without priority dispatch, would only be constrained according to an economic merit order after conventional units.

Feedback Received

BGE believes that all non-priority dispatch RES should be treated the same as all other non-priority-dispatch units in that constraint decisions should be based on an economic merit-order using bids submitted in accordance with bidding rules. The proposal that dispatch down of non-priority dispatch RES for constraints (which should apply on a price basis) should occur before constraining PD units seems reasonable considering otherwise it might in fact undermine the principle of priority dispatch.

CEWEP agree that all renewables should be subject to minimal downwards redispatch, which implies that if there is market-based downwards redispatch of renewables it must occur after the market-based redispatch of conventional generation.

Cloosh Valley Wind Farm agrees with the principle that downward re-dispatching of renewable generation should be minimised. However, they state in their response that it is not clear how the RAs intend to meet the requirements of 13(5)(a) specifically with reference to re-dispatching not exceeding 5%.

In Coillte's view, where new renewables compete for market based redispatch for constraints, this will be problematic as most new renewables will be non-firm, will not be compensated at their DEC offer price, under the BMPCOP will not be able to reflect foregone subsidy, and therefore face material unpredictable grandfathering risk of constraint in the calculation of future revenues. Coillte raise a query that if constraint is market based redispatch, whether this will involve two different commercial merit orders for market-based redispatch, one for renewables and another for conventional generation.

In ESB GT's view, for a non-priority renewable generator, the same principle for conventional units under the BMPCOP to relate complex bids to a unit's opportunity cost would apply limiting the complex bids to the value foregone in the case of TSO non-energy actions.

ESB GT agrees that Article 13(5)(b) places an obligation the System Operators to minimise the downward redispatch of renewable generation. However, it is not considered that this intercedes with the requirement under Article 13(2) for the selection of resource for redispatch to be market based. Article 13(5) places significant obligations on the System Operators to consider the level of redispatch of renewables in the development of the network.

Greencoat Capital note that if constraints on either Priority Dispatch generators or new renewable generators were treated as market-based, all such generators would want to recover their full lost revenues through the market. These lost revenues include the amount of any subsidy, which is currently a disallowed cost in the formation of short-run marginal cost offers in relation to "non-energy actions" under the Balancing Market Principles Code of Practice. In their view defining constraints as market based but denying generation the opportunity to "be financially compensated", noting that the intent of the Regulation is that compensation for redispatching will be based on balancing energy bids, is an inconsistent approach.

Response and Proposed Decision

SEM-20-028 and SEM-21-026 (Consultation on Dispatch, Redispatch and Compensation under Article 13(7)) indicated that constraints would be market based for new renewable units and the preceding sections of this Proposed Decision Paper have outlined the principles for how this would be implemented in relation to submission of PNs, Bids and Offers and interaction of such units in the market. This interpretation is supported by Article 13(1) of the Regulation which states that the *'redispatching of generation and redispatching of demand response shall be based on objective, transparent and non-discriminatory criteria'.* Article 13(2) further states that '*resources that are redispatched shall be selected from among generating facilities, energy storage or demand response using market-based mechanisms and shall be financially compensated'*.

Article 13(5)(b) however requires that TSOs and DSOs take appropriate grid-related and market-related operational measures in order to minimise the downward redispatching of electricity produced from renewable energy sources or from high-efficiency cogeneration. Considering the responses received, the RAs are of the view that while the regulation is clear that measures should be taken to minimise downward redispatching of these types of units, it is clear that Article 13(1) and 13(2) envisage a market based mechanism for applying constraints to all unit types as far as possible. This is in line with the principles of treatment of such units outlined in prior sections of this paper and based on consideration of the responses received. The RAs are of the view that there should only be one merit order for the application of constraints to all non-priority dispatch units.

The RAs note that other elements of Article 13(5) will be dealt with through the TSOs' jurisdictional price controls and these are not within the scope of this paper.

The RAs understand that significant changes will likely be required to the TSOs' systems in order to treat constraints in this way for new renewable units. In order to manage constraints, wind and solar farms are currently grouped together depending on their effectiveness to alleviate constraints. The effectiveness of each wind/solar farm is a function of the topology of the transmission network. Wind/solar farms connected at the same transmission station will generally have the same effectiveness in controlling power flows from that station, so they are grouped together from a constraint management perspective. To apply a constraint, the appropriate predefined group is selected and a MW reduction level specified in the WDT. The WDT then calculates the MW setpoint for each wind/solar farm in the group and issues individual MW setpoints to the control system of each wind/solar farm. This approach will need to be reviewed to accommodate the changes outlined in this Proposed Decision and the RAs request that this is considered in the TSO submission following a SEM Committee Decision on the proposals in this paper.

SEM Committee Proposed Decision:

The RAs propose that constraints will be applied to all non-priority dispatch units based on a market based merit order, based on the bids and offers of such units, accounting for operational constraints and system security.

2.5 Treatment of redispatch (curtailment)

Consultation Proposals

In SEM-20-028 the RAs proposed that curtailment would continue to be applied as it is today on a pro-rata basis across all variable renewable generators, regardless of their priority dispatch status. Under the current market arrangements, curtailment is applied on a pro-rata basis across all non-synchronous generation based on the principle of this being a system-wide issue not related to network and location specific issues.

The RAs stated that there is no distinction between old and new renewable generation under Article 13 for the purposes of the application of curtailment in the SEM and this does not introduce any prioritisation in relation to curtailment of priority and non-priority dispatch renewable generation. Curtailment would therefore continue to be applied to generators in the SEM regardless of whether they are eligible for priority dispatch under Article 12 or not.

Feedback Received

BGE note in their response that units without priority dispatch will be ‘constrained’ before any curtailment is deemed to arise. When curtailment then does arise, it is only RES with priority dispatch that should be affected by curtailment.

Indaver note that in the cases whereby conventional generators and renewable generators may have FPNs that deviate from their ex-ante position, caution must be taken to ensure it does not lead to lost revenues for WtE facilities due to increased curtailment (i.e. if downward resdispatch is shared with new renewables).

IWEA and NIRIG state in in their response that a precise definition of curtailment is required, as the current definition does not adequately differentiate between energy balancing and curtailment. For example, where wind FPNs are far in excess of the SNSP limit, and the TSO dispatches down to the SNSP level, all of that is considered curtailment today and is settled as such. At this moment in time, the judge of what is an energy action (dispatch) and non-energy action (redispatch) are the flagging and tagging principles in the Appendix N of the Trading & Settlement Code. Downwards redispatch of wind farms during a curtailment event, in contrast, is identified by the form of the dispatch instruction sent to the individual wind farms, whether it incorporates an element of “energy balancing” or not.

If the dispatch process decided in real-time that the dispatch down of wind was “energy balancing”, but the action was identified subsequently as redispatch or the instruction was identified procedurally as curtailment, the compensation may be different under the Trading &

Settlement Code than what would have been reasonably expected based on the sharing of the dispatch between new and old renewables. The 'Methodology for System Operator and Non-Marginal Flagging' and the identification of the type of action by the TSO are key processes that need to be considered to ensure that dispatch actions are not inadvertently settled as redispatch and vice versa.

EirGird and SONI state in their response that it not possible to treat priority dispatch and non-priority dispatch renewable units differently for energy balancing but the same for curtailment and constraints. This is because the integrated scheduling process uses the same commercial information to schedule for both purposes. In their view, this approach would still be compliant with the Regulation, as it would mean applying market-based redispatch approaches to non-priority dispatch renewable units ahead of non-market-based redispatch approaches for priority dispatch units, which is within the hierarchy outlined by the TSOs.

Response and Proposed Decision

In the RAs' view, the definition of curtailment as approved in SEM-13-011 remains appropriate as the dispatch-down of non-synchronous generation for system-wide reasons where the reduction of any or all wind or solar generators would alleviate the problem.

However, the way in which this is implemented in current systems, which cannot distinguish between dispatch down of wind or solar units for curtailment (redispatch or non-energy actions) versus energy balancing (dispatch or energy actions), will need to be addressed to accommodate the high-level changes outlined in this Proposed Decision Paper and SEM-21-026. This is also expected to impact on the TSOs' dispatch down reporting methodology.

The TSOs' ruleset to distinguish between constraint and curtailment events was approved by the SEM Committee and published as an Annex to SEM-13-010 in 2013[7] and it would be expected that the terminology used may require some updates given the number of changes to the market that have occurred to date. On this basis, the RAs request that as part of the submission of the TSOs on the design and implementation of the treatment of new renewable units in the SEM, this document is reviewed and updated as required.

In terms of how curtailment is applied, the RAs are of the view that it would be preferable for there to be no change to the continued pro-rata application of curtailment to all non-synchronous units as a form of non-market based redispatch. Article 13(3) of the Regulation outlines the circumstances under which non-market based redispatch may be applied. This

[7]SEM-13-011 was published as an Annex to SEM-13-010 https://www.cru.ie/wp-content/uploads/2016/07/SEM13011-TSOs-Definition-of-Curtailment-and-Constraint.pdf

treatment of curtailment was set out by the SEM Committee in SEM-13-010[8] following an extensive consultation process and no changes to the pro-rata approach were decided on as part of the SEM Committee's Building Blocks Decision Paper for the revised market arrangements (SEM-15-064).

The RAs envision that this pro rata approach would continue to allocate curtailment equally between all non-synchronous units, regardless of whether they are priority dispatch units or the level of firmness of their connection. There are a number of reasons for the proposal to continue this approach, including the system wide nature of curtailment which is only applied to non-synchronous units and which all such units contribute to, consistency in terms of previous SEM Committee Decisions and the non-market based nature of curtailment in the SEM. The continued pro-rata application of curtailment would also be expected to provide a more stable investment environment for new wind and solar units in the SEM and ensure that all non-synchronous units are treated in the same way in this respect.

It is expected that many non-priority dispatch units will be constrained before pro-rata curtailment is applied in order to continue to facilitate priority dispatch generation and the TSOs' rules for dealing with constraint decisions in the first instance. It is also acknowledged that there is often an interaction between constraints and curtailment, which constantly vary in real time. The importance of distinguishing between constraints and curtailment to the greatest extent possible was recognised in SEM-13-010 given their different treatment for market payments. This distinction will become even more important based on the proposals for treatment of redispatch for constraints and curtailment outlined in this paper and energy actions applied to new renewable units in the market.

The TSOs' ruleset to distinguish between constraint and curtailment events was approved by the SEM Committee and published as an Annex to SEM-13-010 in 2013. As noted above, the RAs request that as part of the submission requested of the TSOs on the design and implementation of the treatment of new renewable units in the SEM, this document is reviewed and updated as required. Should the rule set published with SEM-13-011 need to be changed to reflect this, it will be subject to a public consultation and approval process by the SEM Committee.

The RAs understand from EirGird and SONI's response that it is not currently possible to treat priority dispatch and non-priority dispatch renewable units differently for energy balancing but the same for curtailment and constraints. The proposed approach, the TSOs have stated, will

[8] https://www.semcommittee.com/publication/sem-13-010-final-decision-treatment-curtailment-tie-break-situations

involve considerable changes to the fundamentals of how the system is scheduled and dispatched today. The RAs are of the view that this Proposed Decision provides an overview of the RAs' minded to position in relation to the treatment of renewable units in the market, which will require a range of changes to the scheduling and market systems. Implementation of these changes should not be hindered by the way in which units are currently treated however, the RAs understand that such changes will have implications for the practicality, timelines and costs associated with different interim and enduring solutions to be developed by the TSOs. While this is the RAs' preferred approach for a number of reasons as set out above, alternative ways to implement such a solution are welcomed. Feedback on this consideration is also specifically requested from respondents to this Proposed Decision Paper.

Where pro-rata curtailment is applied, it will not be based on any decremental bids submitted by new renewable units without priority dispatch. For curtailment, another quantity would continue to be calculated in addition to the Bid Offer Acceptance for a curtailment action, the Curtailment Accepted Bid Quantity.

SEM Committee Proposed Decision:

It is the RAs' preferred approach that curtailment will be continue to be applied on a pro-rata basis where required to all non-synchronous units, regardless of priority dispatch status.

The RAs anticipate that the terminology used within the TSOs' ruleset for distinguishing between curtailment, constraint and energy balancing, SEM-13-011, may require some updates for new renewable units and existing priority dispatch units based on the principles outlined in this paper. The RAs request that following publication of a Final Decision in this area and as part of the submission requested of the TSOs on the design and implementation of the treatment of new renewable units in the SEM, this document is reviewed and updated as required. Should the rule set published with SEM-13-011 need to be changed to reflect this, it will be subject to a public consultation and approval process by the SEM Committee.

The treatment of curtailment quantities under the TSC would continue to calculate the Curtailment Accepted Bid Quantity for curtailment actions.

2.6 Arrangements for Implementation

Consultation Proposals

The Consultation noted that there may be challenges in implementing a solution to facilitate all of the required changes to comply with Article 12 and 13 of the Regulation within a short time period and that interim measures could be required, with a number of proposals outlined in the Consultation Paper.

Feedback Received

In BGE's view, if there are system delays in implementing a solution which treats new units in the same way as current units, a potential solution could be to schedule such units to forecast availability (or a unit submitted FPN), apply constraint actions and pay for them before constraining or curtailing RES with priority dispatch. BGE note in their response that given the extent of RES development expected over the next decade and beyond in the SEM, the RAs should ensure that the TSOs are in a position to implement necessary system changes to integrate non-priority dispatch RES into the market.

Bord na Mona is of the view that development limitations to Central Market System should not determine policy and renewable generation should be able to submit COD and TOD and participate in the Balancing Market.

In Coillte's view, generation declarations need to be technically appropriate for windfarms (including on an interim basis if required) and if this necessitates changes to Market Systems, these changes should be made. This will require changes to the existing EDIL or Wind Dispatch tools.

EAI is of the view that the scope of implementation work, from design to full implementation, should be strictly time limited (e.g. 12 months) so as to minimise further delay and uncertainty for investors, and potential costs for customers. Energia also supports this view.

ElectroRoute suggests a simple interim measure would be to give any non-dispatchable unit which desired so the option to submit PNs that the TSO scheduling and dispatch processes would be required to use, instead of it being at the TSO's discretion whether to use them. For clarity, units which did not want to submit PNs would not have to and the current approach would be used to set their FPN to their availability. This would be a temporary change until widespread changes can allow these units to fully control their market behaviour (including PNs and COD).

ESB GT believes that once the principles of the implementation are decided there will be an urgent need to progress interim measures to ensure that market participants are not at commercial disadvantage due to a delayed implementation.

Greencoat Capital is of the view that Implementation of an enduring market based system, following the consultation process, will be highly complex to implement as it will require an assessment of system operator dispatch tools (wind dispatch tool and/or EDIL, neither of which seem fit for purpose by themselves without modification), notification procedures for Priority Dispatch and non-Priority Dispatch renewables, classification of the System Operator instructions dispatch or redispatch within the meaning of the Regulation, new settlement rules in the balancing market design, review of the REFIT and RESS rules, etc.

SSE note in their response that the interim solution suggested at the SEMO priority dispatch workshop will need to: define dispatchable plant differently if "deemed PNs" are still retained for some units, resolve how wind units can submit INCs and which system will be used (EDIL, Wind Dispatch Tool or a third option). An accompanying deadline for units to upgrade their systems will also need to be coordinated and signalled early, to allow units to be compliant in time. The registration of the previously non-dispatchable units as dispatchable, will also need to be clarified, i.e. if this is reregistration or change to registration.

Response and Proposed Decision

The implementation of the changes outlined in this Proposed Decision Paper will require changes to the System Operator and Market Operator systems, dispatch tools, the development of new registration arrangements, changes to Market Codes, participant changes and training and coordination between the TSOs, SEMO and affected units.

The aim of this Proposed Decision Paper is to outline the RAs' views on how such units should be treated in the market, without being prescriptive on the manner in which this is implemented, in order to receive feedback on these high-level principles before publication of a Final Decision. The RAs also note the interaction of this paper with the further Consultation Paper on dispatch, redispatch and financial compensation under Article 13(7), which has been published at the same time as this paper (SEM-21-026).

In order to progress this, the RAs propose that workshops as required are held with by TSOs and SEMO with interested stakeholders to discuss the detailed requirements for implementation, with a paper to be prepared by the TSOs and SEMO within three months of publication of the Decision Paper setting out;

1. Changes which can be made as soon as possible to accommodate units, which no longer wish to be eligible for priority dispatch in 2021.
2. An enduring set of arrangements, which can be implemented within 36 months of the Decision.
3. Estimated timelines and proposals for associated changes to registration requirements, market codes and market participant changes and testing.

The RAs propose that this submission will then be subject to final SEM Committee approval.

SEM Committee Proposed Decision:

The RAs propose that following publication of this Proposed Decision;

1. One or more workshops is held by the TSOs and SEMO to discuss detailed design requirements with interested stakeholders.
2. Within three months of the Decision, a paper is prepared by the TSOs and SEMO setting out the detail of interim and enduring implementation proposals and associated timelines.
3. A final proposal should then be submitted to the SEM Committee for approval.

3. Next Steps

Comments are invited on this Proposed Decision Paper until 02 July 2021 and can be sent to gkelly@cru.ie and Gary.Mccullough@uregni.gov.uk. All non-confidential responses will be published with the SEM Committee's Decision in this area.

Once a final decision on these principles is made by the SEM Committee, a proposal for the design of a solution will be progressed by the TSOs and SEMO leading to design and implementation as soon as possible, noting the complexity that will be involved in this process.

In practice, the treatment and participation of such units in the SEM is very unlikely to change markedly until any associated system changes and implementation is complete.