Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch

Consultation Paper SEM-20-028

A Submission by EirGrid plc. & SONI Ltd.

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Contents

1 EXECUTIVE SUMMARY

Regulation (EU) 2019/943 (the "Regulation") is a substantive component of the Clean Energy Package ("CEP"). Article 12 (*"Dispatching of Generation and Demand Response"*) and Article 13 (*"Redispatching"*) of the Regulation proposes changes to fundamental market and operational principles which have underpinned the design and implementation of a range of previous SEM Committee ("SEMC") decisions and national legislation including, but not limited to, SEMC 011-062 and SEMC 13-010. These principles have also underpinned ongoing future Single Electricity Market (SEM) design activity.

EirGrid and SONI believe that it is important to consider these principles, and how to retain the positive elements of these, when assessing how to apply Regulation (EU) 2019/943 to the existing SEM arrangements. Furthermore, we note that the Regulation has been drafted with an overriding focus on the current challenges facing other member states in the European Internal Energy Market (IEM). Therefore some of its concepts are arguably less pertinent to the SEM, given the progress already made in Ireland and Northern Ireland's decarbonisation journey. The challenges that the SEM is currently navigating will be encountered by other member states as they decarbonise to 2040; by contrast, Ireland and Northern Ireland are tackling these challenges in the period from now until 2030.

In that context, we agree with the assertion of the Regulatory Authorities ("RAs") that the level of compensation as outlined in their consultation is unjustified. We also provide additional considerations which might serve to better align the implementation of Option 7 to the intent and purpose of the Regulation, while also acknowledging the critical market and operational decisions previously made in the SEMC. Further we agree that there would need to be a change to the operational and market systems for controllable renewable plant that have no support mechanism to be able to follow their market positon through to real time dispatch (although it should be noted that this facility is not required, nor can it be efficiently delivered for all controllable plant).

More broadly, EirGrid and SONI, as the Transmission System Operators ("TSOs") and Market Operators ("MOs") in Ireland and Northern Ireland respectively, recognise the scale of change to the SEM that is proposed in the implementation of Articles 12 and 13. Acknowledging the complexity of this issue, and the potential ramifications on wider issues (including connection policy, network investment and tariffing considerations), we look forward to continuing to support the RAs in their assessment of how best to apply the Regulation and other relevant legislation to the SEM. We remain at your disposal to discuss the content of this response further, should this be helpful in supporting the SEMC during its decision-making process.

2 INTRODUCTION

2.1 EIRGRID PLC AND SONI LTD

EirGrid plc is the licenced electricity Transmission System Operator (TSO) in Ireland, and SONI Ltd is the licensed TSO in Northern Ireland. Both companies also hold Market Operator (MO) licences in Ireland and Northern Ireland respectively and collectively act as the Single Electricity Market Operator (SEMO), which operates the Single Electricity Market (SEM) on the island of Ireland. Thus, this response is submitted by EirGrid and SONI in their capacities as TSOs and MOs for Ireland and Northern Ireland respectively.

2.2 STRUCTURE OF OUR RESPONSE

In responding to the consultation, in keeping with our recent engagement with the RAs on the application of the Regulation to the SEM, we have adopted a threefold approach.

Firstly, we explore the principles and purpose of the approach from Europe in detail. It is only by examining the intent and purpose of the regulations that we can assess how we can optimally apply these principles to the unique and distinct power system and market of Ireland and Northern Ireland.

Secondly, we consider the practical implementation challenges associated with removing priority dispatch (for the generators in Northern Ireland and Ireland that are captured by the Regulation) and the impact on both the market and operational systems.

Finally, we conclude with our detailed answers to the fifteen specific questions asked in the consultation paper, grouped into themes for clarity. The first theme addresses compensation, the second theme covers which units might be impacted by the proposed changes and the final theme conveys the systems changes that would be required to facilitate any change.

3 BACKGROUND & CONTEXT

The consultation specifically relates to *Article 12* (*"Dispatching of generation and demand response"*) and *Article 13* (*"Redispatching"*) of Regulation (EU) 2019/943. The interpretation of these concepts is central to determining the TSOs' views on the proposals detailed in the consultation. Having sought clarification from the RAs and other stakeholders in the SEM and the wider European Internal Energy Market, the TSOs' interpretation of the Regulation, when considered in conjunction with other regulations and directives, can be summarised as follows:

- Only new renewable generation of less than 400kW in capacity will be eligible for priority dispatch going forward.
- Newly-commissioned renewable generation or high efficiency cogeneration with a capacity greater than 400kW will not be given priority dispatch.
- The dispatching of power-generating facilities and demand response shall be non-discriminatory and market based, which the TSOs interpret as requiring that it is to be specifically driven by ex-ante market trading.
- Priority dispatch shall not endanger the secure operation of the electricity system.
- In general, renewable generation or high efficiency cogeneration commissioned prior to 4 July 2019 will maintain their priority dispatch status in SEM schedules.
- Energy balancing of renewable generation is not treated as TSO redispatch and should not be compensated by the TSOs but through normal settlement of balancing.
- Any redispatch, with regard to constraints, will be linked to the firm access of the generator.

In broad terms, and depending on how the Regulation is implemented, the broad impacts of the Regulation could include:

- Removing priority dispatch from any new large scale Renewable Energy Source for Electricity (RES-E) and Combined Heat and Power (CHP) plant (as they now constitute a large part of the market);
- Re-enforcing that the market position is the main determinant of dispatch (which is a key aspect of self-dispatch markets in Europe, in contrast with the SEM which is a central dispatch market);
- Requiring that compensation is paid to a RES-E or CHP unit if it is dispatched down below its market position, unless it has no guarantee of firm access;
- Requiring the TSOs to guarantee a network capability of at least 50% RES with constraint levels no higher than 5%.

There is a risk that, in the absence of an appropriate interpretation of the Regulation, this could lead to an uneconomical and suboptimal functioning of the SEM and could undermine SEM and jurisdictional policy objectives. EirGrid and SONI would encourage the SEMC to ensure that these potential adverse consequences are included when exploring how best to apply the concepts detailed in the Regulation to the SEM infrastructure. In our detailed response to the specific questions asked in the consultation, we seek to explore how best to balance the effective domestic arrangements that are currently in place with the purpose and intent of the Clean Energy Package obligations. Our proposals in response to this consultation would require careful planning and regulatory endorsement. We do, however, consider these proposals to be feasible and in keeping with the purpose and requirements of the Regulation, as well as tackling inefficiencies in the current interactions of the energy, capacity and system services markets essential for meeting energy policy objectives in the next decade in Ireland and Northern Ireland.

4 INTENT AND PURPOSE OF ARTICLES 12 AND 13: THE WIDER EUROPEAN INTERNAL ENERGY MARKET

The underlying intent and purpose of the Clean Energy Package, including Articles 12 and 13 of the Regulation, needs to be fully understood if its implementation in Ireland and Northern Ireland is to be appropriate and proportionate. The drafting of Articles 12 and 13 are based on market designs and current operational experiences in central Europe. Specifically, Articles 12 and 13 have been developed in the context of self-dispatch markets which are prevalent in central Europe. The overall market design and operational systems architecture have been premised on such a self-dispatch model, whereby units manage their physical positon by bidding in close to real time in the market

Where a TSO in a self-dispatch market reduces the output of a generator in real time below its market position, in most of continental Europe this redispatch down is intended to resolve congestion issues only. Indeed, this is generally how the term "redispatching" is understood and used in continental Europe. This is because network congestion issues in and between other European Member States are well understood in Europe and are becoming increasingly prevalent on the meshed AC grid. It should be acknowledged, however, that there is acceptance within the IEM that, to the extent that a member state's network can be developed so as to remove these limitations, these are short-lived and reasonable, expected deviations from the ideal supply and demand curve. To that end, another underlying principle of the IEM is that the TSO should not to have to pay compensation if they have not guaranteed it; this is, however, offset with an obligation to have an IEM network that can meet 50% RES-E with less than 5% constraints.

The decisions taken to shape the market structure of the IEM differ from the decisions taken to design the SEM in recent years. These are explored in the following section.

5 SEMC MARKET DESIGN CHOICES TO-DATE

In short, there are two distinctive design features of the SEM in Ireland and Northern Ireland which are pivotal to the implementation of Articles 12 and 13. The first is that the SEM operates a central-dispatch power system, rather than the self-dispatch-based model referenced in the previous section. In a central-dispatch-based system, the TSO determines each unit's dispatch instruction, which is informed by Physical Notifications (PNs), but the TSO is not obligated to follow this. There is regulatory oversight of the value and size of differences between the market and the operations output and these are kept within allowable tolerances. The Dispatch Balancing Costs are where this manifests itself.

The other feature is that the SEM is based on an integrated scheduling approach rather than ex-ante bidding close to real time. This sees units in the SEM bid in to the ex-ante schedule to get a position in the SEM and, once this bidding exercise is complete, the operational systems (LTS, RTC and RTD) take over responsibility to ensure that a secure operational schedule is developed to inform real time operations taking Physical Notifications (PNs) as their starting point. There is, therefore, no continuous bidding on behalf of the participants to modify their physical positon, as this will be dealt with in an ex-post settlement. This has some unintended ramifications. Firstly, the manner of constraint calculation is ex-post and there is no current means to feed this information into the TSOs decision making process in real time. Hence, the TSOs systems cannot alert TSOs in real time to the volume by which a unit is being constrained from its market position. In the absence of such data, EirGrid and SONI would challenge whether it is appropriate that the TSOs should compensate units.

The operational systems are predicated on the technical characteristics of the network, rather than the contractual terms detailing the firmness of their network access. Furthermore, while there is ability for the large generators to influence their scheduling in the Long Term Schedule (LTS) and Real Time Commitment (RTC) by how they bid into the ex-ante market, renewable plants, including wind, do not have the same ability. While renewable plants can bid into the ex-ante process, the operational systems are designed to maximize their output with respect to security of the system.

It should also be highlighted that the design of the operational systems has been dominated by conventional plant. While such units account for over 60% of the energy, it is likely that wind will be an increasingly prevalent technology type in the SEM in the coming decade. In order to account for this fundamental change, and to facilitate the further integration of renewables into the SEM, a wholesale review of operational systems will be required at some stage. Any implementation of legislative change should be done in a manner that is to be cognisant of this, and the associated need to retain much of the operational systems for a number of years.

These considerations raise the question of how the concept of redispatch "downward" from a position, as contemplated in the Regulation, can be accurately mapped to central dispatch markets which contain an integrated scheduling approach and ex-post pricing, combined with a high level of renewable generation. The Regulation is based on the principle that downward redispatch from a market position is carried out in order to resolve constraints. It therefore provides for compensation for the loss of a market position. In contrast, in the SEM, curtailment is generally carried out in order to respect SNSP limits and other system-wide requirements. Because continental Europe forms part of a much larger synchronous area in which there is a very significant margin before any SNSP limits are reached, redispatch for these reasons (i.e. what would be curtailment in the SEM), is not generally required. In the current design of the SEM, because of the central dispatch and integrated scheduling model, the market position is less critical in determining the TSOs schedule, hence the use of indicators such as outturn availability that do not represent a market position. Should such considerations determine that the ex-ante market positon in the SEM is the best mapping to Article 13’s market positon, there is a significant and material deviation from what is operational and useable. While EirGrid and SONI are pioneering in RES-E integration we are unable to operate beyond 65% SNSP at present. This situation is not encountered in continental Europe, and in the TSOs' view, the Regulation is not intended to address it. This leads to a level of compensation that the SEMC consider to be unjustifiable and that would be inappropriate to apply to the SEM. It also leads to distortions to the energy market, dispatch imbalance costs, capacity market and system service outcomes. Further, notwithstanding these issues there are additional issues when there are significant volume differences between the ex-ante market and real time that also have to be clarified. All of these issues require clarification through this consultation process.

6 IRELAND AND NORTHERN IRELAND GOING BEYOND 50% RES-E BY 2030

When looking at current system performance, it is accepted that the Ireland and Northern Ireland power systems are pioneering in relation to the high level of instantaneous renewable penetration (SNSP) managed on a synchronous area and the annual non-synchronous renewable production (65% instantaneous, circa 36% wind in 2019). EirGrid and SONI welcome the SEMC's recognition of this in the consultation paper. Furthermore, with the UK target of full decarbonisation of the energy system by 2050 and the Ireland objective of 70% RES-E by 2030, it is clear that there are further improvements to be made in the coming years. From initial estimates, to manage close to 70% annual RES-E from wind, whether onshore or offshore, will require an ability to operate up to close to 100% SNSP for over 35% of the hours a year. The implementation of Articles 12 and 13 have material consequences for the success of these policy objectives.

In 2010, Europe had approximately 18% of its electricity from hydropower renewables. By 2030 it is aiming for 50% of electricity coming from renewables including wind, hydro and solar. The European system is only, therefore, seeking to manage a maximum of 32% of its annual electricity by 2030 from non-synchronous variable generation, such as wind and solar. It is in that specific operational context that Articles 12 and 13 have been developed. When reviewing the performance of the SEM, it is apparent that Ireland and Northern Ireland have not only already exceeded that level (in 2018), but have to meet increased targets which will push the amount of electricity from RES-E in excess of 50% and closer to 70% over the next decade. In this regard, the operational challenges faced by SONI and EirGrid are well in excess of those contemplated by the Regulation. For the reasons set out above, the TSOs consider that simply accepting that Article 13 provides for compensation for curtailment in the context of the SEM does not accurately reflect the intention underlying Article 13, or the Regulation as a whole. Looking forward, other European systems will in future years need to address the challenges that the SEM is currently facing. The SEM is well-placed to support and inform the wider IEM in its resolution of these challenges, as we will soon need to develop solutions, in accordance with the stated direction of Climate Change Policy.

It should be noted that, in the delivery of the *Delivering a Secure Sustainable Electricity System* (DS3) programme, a number of changes must be made in order to manage up to 40% RES-E with 6% curtailment or less. Recent studies for EU SysFlex have corroborated previous DS3 and Facilitation of Renewables work in highlighting the complexity and interaction of these challenges to resiliently operate our power system above 75% SNSP. We would advocate an approach whereby the experience of other comparable synchronous areas is used to inform our response to these challenges. Specifically, we note that the Australian Energy Market Operator recently issued a detailed Renewable Integration Study[1] where it aims to be able to manage 75% by 2025. This report highlights that significant operational and market changes will be required to deliver this; the scale of such changes should be noted in when designing the optimal arrangements for the SEM.

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[1] https://aemo.com.au/en/energy-systems/major-publications/renewable-integration-study-ris

7 SUMMARY POSITION

By way of summary, EirGrid and SONI believe that the application of Articles 12 and 13 to the SEM will require further consideration and analysis in order to identify a holistic implementation plan to deliver value to the end consumer. It is also important to discern the intention underlying these Articles, and to apply it correctly to the very different context of the SEM. This position is derived from the market design considerations made to date (including the integrated market and operational systems that have been designed with a central-dispatch model at their core) and the progress already made by the SEM, in terms of the penetration of renewables. We would hope to ensure that what is ultimately proposed by the SEMC builds on the progress made-to-date, whilst incorporating changes based on the SEM's specific requirements and the overarching intent of the Clean Energy Package.

While our responses to the questions are divided into three categories in the next section, these can be summarised as follows:

- Consideration needs to be given to the precise meaning of the concepts of redispatch and curtailment as used in the Regulation, and how they might be transposed into the SEM infrastructure.
- Previous SEMC decisions have mandated that all windfarms are treated in aggregate with respect to constraints. Based on this, and the pioneering levels of RES-E in the SEM, we believe that the question of compensation requires significant further review.
- The market and operational systems have been designed and built with a central dispatch, integrated scheduling and conventional plant dominated system philosophy. Until there is a fundamental review of these core principles, any changes need to be prudently and pragmatically considered. We would expect the Monitoring Committee, proposed as part of the TSOs' price control submission, to convene to address this and consider how to manage the costs associated with this exercise.
- The SEM design should afford any renewable generators, who do not have priority dispatch status, appropriate options for managing their exposure to imbalance prices.
- The roles and obligations of distribution and transmission system operators need to be clearly defined.
- We need to inform our choices based on the practical realities of information required to appropriately manage the power system, in real time and ex post settlement, including constraint information and changes in aggregate volumes from ex-ante to real time.

8 RESPONSES TO CONSULTATION QUESTIONS

EirGrid and SONI consider that the issues covered in the SEM Committee's consultation on the issues that arise under Articles 12 and 13 of the Regulation broadly fall under three headings. Firstly, there is the issue of compensation under Article 13(7) which is addressed in section 4.4 of the consultation paper. Secondly, there is the issue of eligibility for priority dispatch driven by the provisions of Article 12. Finally, there is the issue of changes to TSO operational systems.

8.1 THEME ONE: COMPENSATION

Consultation Question 14: *Do you agree with the RAs' interpretation of Article 13(7) and the view that the provision of financial compensation to firm generators subject to curtailment based on net revenues from the day-ahead market including any financial support that would have been received represents an unjustifiably high level of compensation?*

The TSOs agree with the SEMC interpretation of Article 13(7) that the provision of compensation based on net revenues is unjustifiably high. We also question whether the connection offers made to date, combined with previous SEMC decisions on "curtailment", are in fact a guarantee of delivery, based on the combination of the commercial terms of a connection agreement combined with the central dispatch arrangements in the SEM. In addition, given Article 13 is explicitly linked to 50% RES-E with less than 5% constraints, it is not clear to what extent compensation for levels of RES-E in excess of this figure by 2030 is applicable.

More generally, SONI and EirGrid consider that paying such compensation is not supported by a purposive interpretation of Article 13, when differences in the approach to curtailment in the SEM and continental Europe are taken into account, as outlined above. With respect to current practice, as we are already operating to 65% SNSP, we consider that simply providing for compensation for all curtailment does not reflect the intention of the Regulation. In addition, for 2030 the EirGrid group is putting in place a comprehensive vision of what is needed to meet the 2030 objectives of both jurisdictions with supporting plans. The augmentation of the DS3 System Services through the Future Arrangements consultation process is critical in this regard. It also goes to the heart of operational systems that need to schedule and dispatch energy and system services from wind, solar, storage, DSUs and interconnectors as well as conventional plant.

The consultation suggests that the monies of compensation on the basis of foregone revenues would be too high for the consumer to bear and, therefore, suggests that compensation would be capped to manage this. While we agree that the levels of compensation are too high and should be considered unjustified, we are not clear that simply capping the rate is the correct approach. This is because it is not clear in the consultation what the precise rationale would be for any cap, nor how this might meet the intent of the Regulation. Furthermore, some of the approaches are inherently unclear and will require additional risk on RES plant bidding into an auction with resultant costs to consumers in the Public Service Levy or equivalent tariff. We set out our suggested approach in response to Question 15 below.

Consultation Question 15: *Which of the options on compensation for curtailment presented above do you view to be most appropriate to adopt in the SEM? Are there additional options that the RAs should consider around compensation for curtailment?*

8.1.1 FEEDBACK ON THE SEM COMMITTEE'S PROPOSALS

EirGrid and SONI have reviewed the options proposed in the consultation and while we would consider that all options might be feasible to implement, we believe that some of the proposals are missing an estimate of what might constitute a reasonable cost. Options which include a cap, either based on volume or a monetary amount, need to clearly define how such a cap is set. This would be a case of working out what is a reasonable cost and then work out an equitable way to pay for it, either weighting across months or seasons with higher levels of curtailment or based on some end of year reconciliation. On this basis, EirGrid and SONI consider that Options 1 to 6 are less viable at this point than Option 7, as Options 1 to 6 require a decision to pay some amount in the absence of a methodology detailing how this might be done.

8.1.2 ADDITIONAL CONSIDERATIONS

EirGrid and SONI consider that any solution should ensure that the market reflects the operational limits in a way that accounts for identified useable energy in the ex-ante market. This would be done in conjunction with a commitment to raising those levels over the decade consistent with meeting the policy objectives in both jurisdictions. This reflects the intention of the Regulation, that compensation should compensate a generator for revenues that it would have obtained in a market (as opposed to revenues from some hypothetical position).

Specifically, applying the SNSP level to the market would ensure that compensation is not paid for volumes that add little–to-no value in the overall process, and it also sends out a clear signal around when additional RES-E should connect to the system. As such, we believe the options of capping the amount of non-synchronous generation that can clear in the ex-ante markets should be explored further. In addition, there should be a firm commercial commitment to raise the ability of the system to levels consistent with meeting policy objectives by 2030. Building on this, increasing SNSP to over 90% to 2030, combined with a complementary reduction in minimum generation/sets/inertia on the system, could then also be considered.

One means of executing this could be to raise a Market Change Request to the auction algorithm to have SNSP limits considered within the ex-ante clearing platform. This approach would have the benefit of embedding the solution in the ex-ante market as opposed to applying bidding restrictions on non-synchronous generators. When implemented in the algorithm, any additional NEMOs that offer services in the SEM will apply the same solution meaning that even with multiple NEMOs, there is a lower risk of levels above SNSP clearing; thus making this a scalable, enduring option. Furthermore, this will make this solution available to other NEMOs across the EU as they face the issues that come with increased levels of non-synchronous generators on their systems.

If it were not possible to implement this directly into the algorithm, it may be possible to implement through the Power Matcher Broker software. This is part of the interface between local NEMO platforms and the central algorithm. This would be less likely to be a multi-NEMO solution; hence any additional NEMOs offering services in the SEM would have to implement their own solution. It would also have the effect of restricting the volume of non-synchronous energy that is offered to the day-ahead algorithm rather than limiting the volume that clears. If not all the volume allowed through the Power Matcher Broker cleared, this could mean volumes of useable energy would not be cleared in the ex-ante market.

A third option could be to implement a local solution by creating additional bidding areas within the ex-ante SEM for sales of non-synchronous generation. This could be done by creating additional areas each connected to the main Euro and GBP areas already implemented. Virtual interconnection capacity between the areas would be set by the TSOs based on SNSP levels, thereby ensuring that the volume of non-synchronous generation that can clear and "export" to the main currency area is limited to the level of SNSP that can be accommodated on the system.

In considering these options, EirGrid and SONI have engaged with our NEMO service provider on these matters. From these initial discussions, it would appear that all three of these options are implementable and we look forward to continuing this engagement further to understand how this might be delivered, as well as any potential adverse impacts on the performance of the ex-ante markets (noting that further trialing would be needed). Under these options, any decision to compensate non-synchronous generators who are subject to downward redispatch would mean that this compensation is limited to redispatch of energy only up to SNSP levels.

Should these options not be implementable, EirGrid and SONI believe that a further ex-post settlement option could be explored; however, rather than being based on a volume or monetary cap, this could be by limiting the volume that is subject to compensation to the SNSP levels. This could be an ex-post calculation that would flag volumes that have been curtailed due to SNSP limit as not subject to compensation while further curtailment would be compensated.

In the TSOs' view, these options better reflect the intention underlying Article 13(7), namely that compensation should only reflect a genuine loss to the generator by reference to a market position that is feasible from the point of view of both the generator and the total system (i.e. reflecting an ex ante position that takes into account SNSP limits).

8.2 THEME TWO: ELIGIBILITY

Consultation Question 2: *In terms of the practical implementation of Article 12(1) to introduce a distinction between units which retain eligibility for priority dispatch and those which are not eligible, the RAs propose;*

Where a commissioning programme has been agreed with the TSOs on or before 4 July 2019, it is proposed that such units will be eligible for priority dispatch.

Where a unit is eligible to be processed to receive a valid connection offer by 4 July 2019, the RAs are of the view that this represents a contract concluded before priority dispatch ceases to apply under Article 12 and that such units are also eligible for priority dispatch.

Where a unit becomes active under a contract concluded before 4 July 2019 including a REFIT letter of offer or PPA, the RAs welcome feedback on the proposal for such generators to be eligible for priority dispatch.

Interested stakeholder's views are invited on these proposals.

EirGrid and SONI would welcome clarification on what is meant by the notion that "*(the) commissioning programme has been agreed with the TSOs*". The current assumption is that this relates to energisation and Grid Code testing, including for distribution connections, rather than a programme for construction.

Where the consultation proposes that "*a unit becomes active under a contract concluded before 4 July 2019*", EirGrid and SONI consider that a clear definition of the term "contract" is required, in order to ensure that this is commonly understood. By way of illustration, neither REFIT nor PPA contracts fall within the remit of the TSOs or DNOs. Decisions in respect to eligibility also need to reflect the differences in the connection processes in each jurisdiction of the SEM.

Considering the proposed options, EirGrid and SONI would advise that clarity is provided. Upon review, it could be argued that the second point might make the first redundant; in order to have an agreed commissioning programme, a unit should already have a connection agreement in place. Similarly for the third point, we are not aware of any such contracts or PPA that were entered into before July 4 which would not have required a connection offer. Hence, a simpler definition could possibly read as follows:

"Where by 4 July 2019 a unit:

- *(i) has executed a connection offer, or*
- *(ii) has received a connection offer which has not yet lapsed, or*
- *(iii) is eligible to be processed to receive a valid connection offer (i.e. has an application deemed complete/effective)"*

***Consultation Question 11**: The RAs’ interpretation of the Regulation is that where a new connection agreement is required or where the generation capacity of a unit is increased, a unit will no longer be eligible for priority dispatch.*

The RAs also propose that units should be able to make a choice on whether they wish to retain their priority dispatch status or not. Feedback is requested on this proposal.

The Regulation provides that priority dispatch no longer applies from the date on which the unit becomes subject to "significant modifications." This is deemed to be the case at least where a new connection agreement is required, or the generation capacity is increased. The definition of *significant* modification is open to interpretation, and also what might constitute a ‘new’ connection agreement. The TSOs may issue a modified connection agreement for a number of reasons, many of which are not material, or reflective of any *significant* modification to the unit itself. EirGrid and SONI suggest that it would not be in line with the intention of the Regulation that a unit should lose priority dispatch for changes to the connection agreement that are not material and do not reflect *significant modifications to the unit*. We also suggest that the *significant* modification concept should be aligned with the ‘material change’ that triggers whether or not Network Codes requirements are applicable to a unit under a connection agreement.

The concept of material change can also include references to ‘change of technology’ and ‘change of running regime’ and some allowance for this may also be required.

To provide additional clarity, we would propose the following concept be applied to the RAs’ proposal:

“Modifications to the Connection Agreement should not impact the Customer’s Priority Dispatch status, except where the following applies:

- *the modification provides for an increase in MEC;*
- *the modification provides for a change in technology type;*
- *the modification provides for a change in the manner of operation of the unit;*
- *the modification provides for a repowering which may lead to an extension to the duration of the Connection Agreement.”*

8.3 THEME THREE: OPERATIONAL SYSTEMS

***Consultation Question 1:** Do you agree with the RAs’ interpretation of the requirements under Articles 12 and 13 and specifically the application of dispatch, redispatch and market based/non-market based redispatch in the SEM?*

EirGrid and SONI consider that Articles 12 and 13 of the Regulation are written in the context of a predominantly self-dispatched IEM. In the context of the SEM, however, the application of Central Dispatch and integrated scheduling need further consideration, with respect to the concepts of dispatch and redispatch (both market based and non-market based) in the Regulation. In the SEM, the concepts of dispatch, market based redispatch (or balancing) and non-market based redispatch, as considered in the Regulation, are more complex in its transposition to the SEM. In particular, it is clear that redispatch in continental Europe is understood as meaning an action taken in order to resolve constraints, i.e. targeted at generation in a specific location, rather than in order to resolve a system-wide issue such as SNSP limits. In addition, while on its face a Physical Notification in the SEM, in principle based on an ex ante market trade, is analogous to a self-dispatch decision in continental Europe, in the SEM the TSOs process after this point is to apply its multiple objective functions as set out in the Balancing Market Principles Statement as part of a single process. Consequentially, it is not clear before actions are taken what the exact reason for the action is. This is critical for the TSOs to dispatch to this information. It is not until after this stage that the unit can be considered to be fully dispatched.

The integrated mechanisms in the TSOs' decision support tools will provide results that will set out changes to generators' output based on the following objectives in the most optimal manner possible:

- ensuring operational security;
- maximising priority dispatch generation;
- minimising the cost of deviations from physical notifications;
- as far as practical, enabling the ex-ante market to resolve energy imbalances; and
- as far as practical, minimising the cost of non-energy actions.

Given this, it is not clear before actions are taken what the reason for each action is. This has resulted in the implementation of an ex-post tagging and flagging process to inform imbalance pricing and settlement. This process examines the actions taken against pre-defined requirements to determine if the action was required for energy balancing or for non-energy or system reasons.

EirGrid and SONI would have a concern if future design over-rigidly applied an approach intended to reflect the European self-dispatch model rather than the central dispatch model that has been implemented for the SEM. Many of the concepts outlined in the Regulation and the RAs' consultation seem predicated on the view of system operations as a multi stage process with a clearer distinction between balancing actions needed and non-market based redispatch to manage congestion issues. For example, Article 13(3) notes that non-market based redispatch may be used where no market-based alternative is available. This is not the case in the SEM where all decisions are made as a result of the Integrated Scheduling Process. The TSOs in the SEM will not take actions in advance with any clear knowledge whether the action is a balancing action or non-market based redispatch. As such, the interpretations may be appropriate when it comes to ex-post review and reporting but it needs to be clearly understood that this approach does not have a practical application in the central dispatch model applied in the SEM.

The consideration of self-dispatch concepts in SEM fundamentally requires a material philosophical redesign of the market principles and the supporting operational systems. It might be that such a review would be appropriate in several years' time, but it should be noted that all forward-looking activities currently being undertaken by the TSOs, including those done in conjunction with the RAs, have the central dispatch model as their core assumption. These include discussions relating to Price Review 5 (including the associated network development) and relating to the comprehensive vision of what is needed to meet the 2030 objectives of both jurisdictions with supporting plans.

***Consultation Question 3:** It is the RAs' understanding that any unit which is non-renewable dispatchable but is no longer eligible for priority dispatch can be treated like any other unit within the current scheduling and dispatch process, through submission of PNs with an associated incremental and decremental curve. Feedback is requested on this aspect of implementation of Article 12 of the new Electricity Regulation.*

The issue as described relates to both market and operational systems. The current market design contains detailed rules for non-renewable dispatchable generators which are normally considered as conventional generators. The rules also allow for conventional generators who attain Priority Dispatch status under other provisions than the RES directives. This applies to high efficiency CHP generators and peat stations. Under the current SEM arrangements, dispatchable generators with Priority Dispatch are still required to submit PNs and Commercial and Technical Offer Data to the TSOs. Within the TSOs' scheduling and dispatch systems, such units are considered to have Priority Dispatch up to the value of their Physical Notification. These generators should be dispatched to their PN level. They can be called on for additional output for any volumes above their PN up to their availability based on their position in the merit order.

It is our expectation that, with the new rules for Priority Dispatch, any similar units will register in the SEM simply as a dispatchable generation with no Priority Dispatch. With this configuration, the TSOs' scheduling and dispatch systems will simply treat these units as a standard dispatchable generator, the same as any other conventional unit in the market. As such, they will continue to be required to submit a Physical Notification and Commercial and Technical Offer Data to the TSOs; however, the operational systems will consider such units for both upward and downward redispatch for balancing or constraints based on the commercial data set provided.

As such, 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.

***Consultation Question 4:** It is proposed that any unit which is non-dispatchable but controllable and is no longer eligible for priority dispatch would run at their FPN, be settled at the imbalance price for any volumes sold ex-ante and could set the imbalance price.*

As part of this proposal, there is a question of whether such units would be required to submit FPNs or where no FPN is submitted, the unit could be assigned a deemed FPN calculated by the TSOs as per the process today. Where a unit elects to submit an FPN, in this case, the TSOs would be required to use this as long as it does not deviate above a certain percentage of the TSOs' own forecast availability of the unit.

As an alternative or as a possible interim measure, taking account of the zero marginal cost nature of non-dispatchable but controllable generation in the market today, i.e. wind, solar, units no longer eligible for priority dispatch could be scheduled to their availability as per the process today on the assumption that this reflects economic dispatch in any case, but where there is excessive generation on the system such units would be subject to energy balancing prior to any priority dispatch units.

In particular, the RAs are seeking feedback from the TSOs on measures which can be introduced to facilitate required compliance with the new Electricity Regulation within the scheduling and dispatch and balancing market systems.

The distinction between dispatchable and controllable is captured in the EirGrid and SONI Grid Codes and is embedded in previous hierarchy orders from the SEMC. Largely, it evolved out of the consideration of windfarms in the early 2000s in Ireland and Northern Ireland. At this time, windfarms were seen as relevant to operations but their influence on the system was less prevalent than it is now. To that extent, windfarms had to have the ability at times to be "dispatched" to a lower amount. While this was rare at the time, there was an obligation for these systems to be in place. An additional consideration was that a windfarm was unable to provide certainty that their output would remain at that dispatch level due to the changes in wind. For these considerations a new class of generator known as "controllable" was created. All of these units are dispatched directly from the TSOs' control centres in Dublin and Belfast.

EirGrid and SONI are of the view that controllable units, who are not eligible for priority dispatch should, where possible, be treated in the market systems as dispatchable and submit Commercial Offer Data and Physical Notifications (PNs). In this case, we do not agree with requirements around PNs being within certain tolerance of forecast, and being replaced by forecast if not close enough or if not submitted at all. 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, we would interpret that the unit should be run to that PN level (unless for reasons for balancing etc.). We believe replacing this PN with availability in this instance would not be correct.

We do not agree that the proposed interim measure meets the intention in Regulation of removing priority dispatch. It appears to maintain the exact same treatment for controllable non-dispatchable units as is currently applied. We agree, however, that in the absence of these units being able to become dispatchable in both the market and operational systems, interim measures like these are the only practical ones available.

Given this context of the current market and operational systems, there are practical considerations that need to be made on transitioning of "controllable" plant to "dispatchable" plant. From a market perspective we would envision that the unit will need to submit both Commercial and Technical Offer Data. These 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. Furthermore, there will need to be some simplified Technical Offer Data developed. More importantly is the interaction with a range of other operational systems including the Wind Dispatch, forecasting, and scheduling and dispatching reserves tools. We believe a pragmatic consideration would allow the ability for some of these controllable plants to be transitioned and be removed from the other aggregated systems so there is no market or operational double counting. However further work is needed to understand how to interpret and change the proposed interim approach to ensure it meets the intention of the Regulation as much as possible, within what is practically achievable.

If the proposed approaches are considered, 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. By way of illustration, we would need to ascertain 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.

Consultation Question 5: *Feedback is invited from interested stakeholders on the treatment of non-dispatchable and non-controllable units.*

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 Commercial Offer Data 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.

For considerations of meeting renewable targets, the impact of congested distribution connected non dispatchable and non-controllable plant needs careful thought. It is arguable that these plant are to be included if they are a material part of making the 50% RES-E with 5% constraint target. In any case, clarity on the roles and responsibilities of the relevant system operator and the application of these regulations to transmission and distribution plant is required.

Consultation Question 6: *Do you agree with the RA's interpretation that new generators which are no longer eligible for priority dispatch (both dispatchable and non-dispatchable but controllable) will be subject to energy balancing actions by the TSOs, considered in dispatch economically and settled like any other instance of balancing energy?*

EirGrid and SONI agree with this interpretation that energy balancing of renewable generation is not treated by the TSOs as redispatch and should not be compensated as such. It should therefore be considered in dispatch economically and settled in a similar manner to any other instance of balancing energy. The TSOs have already acknowledged that this interpretation does mean that a number of TSO and market systems will need to be modified in order to implement these changes. This will require more time to carry out impact assessments and cost estimations with the various system vendors. An interim solution could be applied, where new non-priority dispatch renewable generators are treated as fully dispatchable, while a longer term solution which takes into consideration the next evolution that the SEM needs to take over the coming years to include other longer term market design implementation needs.

Consultation Question 7: *What is your view on the application of bids and offers to zero-marginal cost generation?*

EirGrid and SONI agree that bids and offers should be applied to zero marginal cost generation units when they are non-priority dispatch in scheduling and dispatch, and settlement, in the same way as other units.

This appears to be one of the primary aims from these changes introduced by the Regulation, where these units can trade in the energy markets reflecting their value, not just their cost, thus preventing a future where a large proportion of the energy market is dispatched on a different basis than value-based bids. This would mean the Commercial Offer Data (COD) these units can submit to the balancing market should reflect the same requirements of other units, where they can bid freely for Simple COD, and based on the Balancing Market Principles Code of Practice (BMPCOP) for their Complex COD, with the same rules for using each of these price types in scheduling, dispatch, pricing, and settlement as they are used for other units.

This should be considered alongside the other areas of the consultation. By way of illustration, if bids and offers are to be submitted for these units for energy purposes, it would not be possible to use other prices, such as those of the priority dispatch hierarchy, for non-energy purposes. Hence, these units with bids and offers would be scheduled to be re-dispatched down first for non-energy purposes, following the economic merit order alongside all other relevant units, ahead of priority dispatch units who would be re-dispatched down pro-rata in the order of the hierarchy. In turn, this would impact the compensation considerations, as using these bids and offers in the same way as for other dispatchable units in settlement (i.e. remunerating units through Imbalance Component Payment or Charge, and Premium or Discount Payments) may be different to the approach for compensating priority dispatch units which do not have bids or offers.

The BMPCOP should take care in considering the Complex COD allowed for non-priority dispatch renewable units against the level of compensation for priority dispatch units, taking into account the principles outlined for non-market based redispatch compensation and the decisions made in this consultation relating to the level of compensation for these units. The combination of these aspects would interact with the rationale for decisions around other items, such as tie-break rules or taking market-based redispatch of non-priority-dispatch units ahead of the priority-dispatch hierarchy.

If the prices permitted under any BMPCOP revisions and allocated compensation under Article 13 would result in full recovery of revenue for supports and wholesale market energy, then under any scheduling and dispatch approach or tie-break rule for dispatching down, the new non-priority-dispatch units would not be disadvantaged in the wholesale market.

This consideration is only possible for units which are dispatchable. For controllable units, the approach of considering them in the priority dispatch hierarchy for dispatch down from their availability may be the only option available.

If the aspiration is to create some recognised difference between the non-priority dispatch controllable units and the priority dispatch controllable units, another variant on this could be to have the non-priority dispatch renewable units considered as the first point in the dispatch-down hierarchy. This could be done with a change in priority dispatch hierarchy price parameters to reflect this, such that they would be dispatched down after all market-based redispatch but before all priority-dispatch units. In this sense, controllable units may not use their own market-based COD. Only dispatchable units can do this, while controllable units can be scheduled based on non-market based dispatch down hierarchy parameters.

This may either drive an approach that all non-priority dispatch renewable units must be developed in a way where they are dispatchable, or, if there is an allowance for controllable units, this needs to be a continuation of the current approach as an interim measure until these units can be considered dispatchable while the enduring design is developed.

***Consultation Question 8**: What is your view on a potential rule-set being implemented for non-dispatchable units where (a), systems cannot facilitate ranking of decremental bids for such units for balancing actions for a certain time period and/or (b) where convergent bid prices require a tie-break rule?*

EirGrid and SONI agree that bid offer prices should be the primary basis for ranking the order in which actions are taken on these units in the same way as other units.

If there are convergent prices, then whether a pro-rata or a different tie-breaking approach makes most sense or are possible will depend on the systems being considered and the levels of compensation for different unit categories. Certain approaches to tie-break rules may result in complexities and lead times in developing systems to allow for a change.

More generally we consider that those controllable units that retain priority dispatch should be treated in a similar fashion as today. Invariably these units retain state aid supports that mitigate the financial aspects of balance responsibility to a large degree. The exact nature of this rule set will need careful consideration. Due to systems design and pragmatic consideration, we would recommend that there is no fundamental change for how controllable priority dispatch units are treated until a fundamental redesign of the market, including self-dispatch considerations is made. However, we acknowledge the need to allow some new unsupported plant and some old plant failing out of support to set their ex ante market positon and where the TSO will aim to follow this position in scheduling and dispatch. It is this challenge that we think can be pragmatically achieved in the current systems with a reasonable effort.

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 the current conventional units.

At a high level, EDIL is the tool used to issue instructions to dispatchable units, while the Wind Dispatch Tool is used to issue instructions to controllable units. The Wind Dispatch Tool is where most of the current priority-dispatch tie-break logic, such as calculating the pro-rated output reduction, or differences between units for constraints based on firmness etc. Controllability instructions, such as CURL, LOCL, and their ending instructions, are issued through the Wind Dispatch Tool, while no dispatchable instruction types (such as MWOF) are issued through this system. EDIL instructions tend to be based on output levels suggested through the Market Management System (MMS) scheduling and merit orders.

The MMS approach to tie-break situations on an individual unit level does not consider the same kind of logic as the Wind Dispatch Tool. One reason is that it takes into account all system and network constraints, operational characteristics, system service requirements, and energy balancing considerations, in one optimization. As a result, considering why one units dispatch position is being suggested at a particular level cannot be easily broken down along heuristic rules such as an action being clearly only for curtailment and therefore should be based on pro-rating. This kind of logic does not currently exist in the systems and would be difficult to implement in any co-optimisation. For this reason, a separate tool, the Wind Dispatch Tool, is used to apply these rules. The tie-break logic used by MMS is instead to apply small random adjustments to the prices used (in scheduling only).

Based on this, there are system change implications to the question being asked. In the short term, it would not be possible to apply a pro-rata rule for dispatch down of units if they are scheduled through the MMS, which would be required for the dispatchable non-priority dispatch renewable units being discussed, as they would be dispatched through EDIL rather than through the Wind Dispatch Tool. Either changes to be able to dispatch these units through the Wind Dispatch Tool would be needed, or changes in the underlying MMS scheduling logic would be needed. Both of these approaches would represent significant changes to IT systems which would need to be impact assessed once a detailed design is completed.

The impact this has on the affected units depends on decisions made on compensation. If market-based redispatch is considered, then units would be remunerated based on the better of their COD prices or the imbalance price, in which case they can state the impact of being turned down and receive sufficient compensation for it. If non-market based redispatch is considered, then the compatibility of the scheduling approach depends on the decisions made on the level of compensation. If units are not compensated, partially or fully, for curtailment, then those units which are selected to turn down first would be impacted more than the other units. This would not necessarily be systemic against certain units, as the logic for choosing one unit over another in a tie-break in the scheduler is a randomised one. This may even out the effect somewhat over time, but when considering an isolated instance, a pro-rata approach may be considered fairer.

Consultation Question 9: *Do you agree with the TSOs' proposal for a revised priority dispatch hierarchy?*

The RAs request that the TSOs consider the points raised in this Section in their response with any further proposed changes to the hierarchy.

EirGrid and SONI wish to clarify that in providing the RAs with an updated hierarchy for non-market based redispatch as requested, a fuller context around the recommendation was also provided. At a high level, the TSOs recommended that the hierarchy remain much the same with some minor wording amendments to account for the new operational and market changes in the context of high penetration of renewables and high efficiency CHP. It was also developed in consideration of the option for implementing a possible solution for Article 13 or the Regulation by including a limit in the ex-ante market that would take the SNSP level into account. This is the implementation option presented in this response.

Regarding the specific questions the RAs have asked the TSOs for clarity on in in this section of the consultation, the items below seek to expand on the proposals in the TSOs' original submission.

1) **The proposal of aligning the SNSP level in the ex-ante market:** This proposal would include the System Non-Synchronous Penetration (SNSP) trajectory (as part of the next phase of DS3) to 2030 in the ex-ante market limits for the SEM. For example, when the TSOs reach 70% SNSP this limit would be incorporated as a limit in the ex-ante markets. Thus the amount of renewable generation allowed to clear would be capped at the applicable SNSP level. We have expanded further on implementation options in our response to consultation Question 15.

2) **The Peat plants were omitted from the hierarchy provided to the RAs:** The reason for this was that the current hierarchy would be maintained at present until such time that the ex-ante market solution with the SNSP limit could be achieved at which point the new proposed hierarchy would come into effect. This is based on the understanding that the peat generators will no longer use the same fuel source and these units would be converted to biomass in the next two to three years.

3) **The definition of an Autoproducer in the context of the proposed hierarchy:** The TSOs have operational security concerns with the definition of an Autoproducer and how this interacts with the de-minimis dispatchable level for the size of plant and the consequences to overall system security. This is an issue that needs further consideration.

4) **Hydropower:** The TSOs, in our submission to the RA in January, had a typographical error. The TSOs are proposing the existing hierarchy remains unchanged. In that regard, hydropower plant, which has storable useable energy, would be considered to be dispatched down before wind and solar.

Consultation Question 10: *Feedback is requested from interested stakeholders on the types of demonstration projects that may be suitable for an application process for limited priority dispatch eligibility.*

EirGrid and SONI TSOs are of the view that any demonstration project that would be seeking limited Priority Dispatch would have to follow the normal Regulatory Authority approval process. As part of this process, the TSOs continue to be open to discussing any demonstration project that may wish to connect to the power system and join the SEM. If the particular project is designed to provide system services then it can apply to demonstrate specific service capability through the Qualification Trial Process; however, there is currently a 1 MW minimum contracted volume per single provider. Demonstration projects wishing to provide energy and participate in the SEM would follow the normal registration process for the energy market and balancing arrangements. These projects would be reviewed on a case-by-case basis as due to the new 400 kW limit on Priority Dispatch Projects analysis would need to be carried out on how they would be dispatched from a system perspective and also the interaction with the DSO or DNO.

Consultation Question 12: *Do you agree with the RAs' interpretation of Article 13(5)(b) whereby 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, the only difference between renewable generators and HECHP eligible for priority dispatch will be how they are treated in terms of energy balancing.*

As explained above, EirGrid and SONI are of the view that the intention of the Regulation is to solve the congestion issues that exist across many other European member states' synchronous power systems that operate on a self-dispatch basis where high levels of SNSP do not exist at present. The TSOs do not believe that the Regulation is fully reflective of the context of the Ireland and Northern Ireland; a centrally-dispatched island system with limited levels of EU interconnection and high levels of renewable penetration, all alongside an integrated scheduling process.

While the TSOs fully support the policy to minimise the downward redispatch of renewable generation and HECHP (as per the current hierarchy published in SEM-11-062), there is a difference in the interpretations of the Regulation between the TSOs and that which has been included in the consultation document. For the reasons set out above, the TSOs believe the true intention of the Regulation is to compensate for the curtailment of useable energy (i.e. reflecting a feasible market position). In that regard, we believe that the intention of the Regulation is that material technical issues may be reflected in the energy market, for example by means of redispatch in this case, as long as there is a planned approach to removing these over time. This is reflected in the sizing of bidding zones (coupled with long-term support for greater interconnection) alongside obligations that the TSO is not required to pay compensation if the connection agreement does not guarantee it; however, the TSO does have to build out a network to meet the 50% RES targets.

Based on this understanding of the intent and purpose of the Regulation, we consider there is an option that better meets its intent (namely that generators should be dispatched – either by themselves or by the TSO – to a feasible market position and should only be compensated accordingly) and the unique challenges of the Ireland and Northern Ireland system. Specifically, we believe that that it would better reflect the intention of the Regulation to provide for compensation based on a position in the ex-ante market linked to SNSP (as referenced in our responses to Question 9 and Question 15) and giving a firm commitment to raise the effective SNSP to 95% by the end of the decade where compensation of "curtailment" events would be appropriate. The implementation of this will be challenging and will require a dedicated focus. Failure to do this though could seriously undermine the effectiveness of the markets (Energy, Capacity, System Services) in their support and facilitation of government policy on Climate Change in both jurisdictions.

It is important to emphasise again that it is 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. We believe this 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.

It is also important to clarify a number of aspects related to market based and non-market based redispatch. The first aspect is that it would be assumed that all market-based mechanisms would be used as much as possible before using non-market based mechanisms. This would serve to ensure that the non-priority dispatch units are utilised first before priority dispatch units. If there are renewable units within the market-based mechanisms, then we would interpret that there should not be a separate rule for how to deal with these units over the treatment of other market-based redispatch units. The *"appropriate…market-related operational measure"* in this case is to follow the merit order of the prices submitted by units. If the prices are submitted in such a way that a renewable unit is the most economic to dispatch down, then it is proposed that this would be an appropriate interpretation of the requirement. This does not necessarily translate directly to priority dispatch or non-priority dispatch, but could depending on decisions made relating to how these types of units map to market or non-market based redispatch approaches. If it is determined that all renewable units are subject to non-market based redispatch, regardless of priority dispatch there would be no differences between them. However, if it is determined that through the COD submitted by the non-priority dispatch renewable units that they should be subject to market-based redispatch, then there would be a difference in treatment depending on priority dispatch status. The differences between renewable units and high efficiency CHP units would be based on merit order for energy purposes, and based either on merit order for market-based redispatch, or based on the priority dispatch hierarchy order for non-market based redispatch.

***Consultation Question 13**: Do you agree with the RAs' interpretation of Article 13(6) and the introduction of a new hierarchy for the application of non-market-based downward redispatching?*

Article 13(6) sets out a new hierarchy for the management of renewables and High Efficiency Combined Heat and Power (HE CHP) during constraint and curtailment events, which is different to the existing SEM hierarchy under SEM-11-062. This needs to be considered and the full set of rules in the hierarchy need to be re-evaluated, including whether the treatment of minimum generation for other renewables is supported by the Regulation.

As stated earlier in our response, there is a risk that the market schedule is likely to be system services deficient at high levels of RES-E, depending on the implementation of the Regulation driving the need for significant redispatch. In such scenarios, the TSOs believe it might be necessary to consider the required system services as a rationing mechanism as priority dispatch should not ultimately threaten the integrity and security of the power system.

If the actual useable renewable energy is incorporated into the ex-ante market, as proposed by the TSOs, the following hierarchy (when rationing market quantities in an over-subscribed RES-E and CHP world) could be proposed:

1. The market to allocate based on day-ahead price or imbalance a market position for all participants that solves the energy balancing and SNSP restrictions. This shall give a market positon that is effectively dispatch for these units;
2. Where there is a need in operation to redispatch down from these market quantities then redispatch High Efficiency Cogeneration / Biomass/Waste to Energy to minimum generation (level where they are considered autoproducing: if they are not an autoproducer turn off);
3. Wind, Solar, Tidal ,Hydro;
    a. Windfarms which should be controllable but are not in practice
    b. Windfarms which are controllable;

    c. Windfarms which are exempted or are not expected to be controllable;
4. Redispatch High Efficiency Cogeneration / Biomass/Waste to Energy off,
5. Interconnector schedules; and
6. Generation the dispatch down of which results in a safety issue to people.

This order of the redispatch respects the new consideration in Article 13, while also being consistent with the security of supply considerations in SEM 11-062. Where we are comfortable in operating a power system with high RES, in keeping with the design principles of the DS3 and DS3+ programmes, it is more secure to turn down the units who have a certain energy output over multiple hours than those that are more uncertain. In this case, hydro and tidal would potentially come before wind and solar. However this would need to be checked against the regulations. There is also the need to fully understand the implications of this from a system change point of view.