Response to SEM-21-026 (on redispatch compensation) and SEM-21-027 (on renewable dispatch)

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Contents

1 INTRODUCTION

The Irish Solar Energy Association (ISEA) was established in 2013 to advance a policy and regulatory landscape promoting solar as a leading renewable energy technology that will decarbonise Ireland's electricity system and contribute to a successful and strong clean economy. As the leading voice for the Irish solar industry, ISEA works closely with stakeholders to advance the solar agenda on behalf of our members. ISEA is committed to delivering at least 5,000 megawatts (GW) of solar in the next nine years to make a significant contribution towards 2030 energy targets and achieve a diverse and clean electricity network. As the trade association for the solar industry in Ireland, ISEA is responding on behalf of our membership of more than 150 parties currently active in the Irish solar market.

The Clean Energy Package for all Europeans ("Clean Energy Package") has a number of objectives when it comes to the electricity market arrangements. Regulation EU/2019/943 ("the Regulation") seeks to break down barriers for consumers and innovative distributed technologies, promote flexibility, and promotes the concept of the active energy citizen. It also seeks to place renewable energy and conventional energy on the same footing, competing on a like-for-like basis while respecting the differing technical characteristics of different market participants. Core to the Clean Energy Package's existence, however, is the "*common goal of decarbonising the energy system*".

This decarbonisation should be done as efficiently as possible, within the spirit of the Directives and letter of the Regulations set out by the EU Institutions. This will require efficient investment in new renewable generation, which in the context of Ireland and Northern Ireland means further development of solar and wind generation. These technologies are non-synchronous and have zero marginal cost of production, leading to new system and market behaviours at high levels of penetration.

Where the solar and wind technologies do differ, however, is in their impact on network investment costs and the profile of their production. Solar generation can – and frequently is – located closer to electrical demand, potentially minimising requirement for transmission infrastructure. Furthermore, solar generation development in Ireland and Northern Ireland is starting from a relatively modest base, with low levels of correlation with pre-existing renewable energy production, solid correlation with system demand, which both lead to lower projections of curtailment and constraints.

Diversification of the renewables portfolio and blending in higher volumes of solar technology onto the all-island system has benefits. A 2021 report by AFRY Management Consulting[1] found substantial reductions (of the order of 40% by 2030) in the volume of all renewable curtailment, through increasing solar PV generation.

This, in turn, leads to lower costs to consumers in the delivery of Ireland's and Northern Ireland's renewable ambitions.

[1] https://irishsolarenergy.org/wp-content/uploads/2021/03/AFRY_ISEA_The-Value-of-Solar-in-Ireland_v300.pdf

That said, we accept that increased solar generation may experience comparable constraint and curtailment issues to other renewable generation. This challenge, however, will take some time to emerge (with the exception of areas where there are pre-existing constraint issues). Solar generation's day-time production profile correlated with demand requirements and its weak correlation with wind in the all-island market means that there is a considerable transitional period where renewable-unserved demand can be supplied with solar energy. These characteristics, along with its close-to-demand-locations also mean that available existing network capacity can be more efficiently utilised prior to material constraints becoming binding under normal network conditions.

It is this opportunity for efficient solar generation investment which has informed ISEA's response to this consultation.

ISEA therefore welcomes the opportunity to respond to "Consultation on Dispatch, Redispatch and Compensation Pursuant to Regulation (EU) 2019/943" (SEM-21-026, "the Consultation Paper"), "Proposed Decision on Treatment of New Renewable Units in the SEM" (SEM-21-027, "the Proposed Decision Paper"), and the Regulatory Authority joint response to Wind Energy Ireland and RenewableNI's correspondence (SEM-21-056, the "RA Letter"), together the "SEMC Papers".

1.1 EXECUTIVE SUMMARY

ISEA supports the following positions:

- ISEA believes that compensation for downward redispatch should be at the level of financial support, be it market-based compensation pursuant to Article 13(2) or non-market based pursuant to Article 13(7).
- ISEA supports downward redispatch for constraints being market-based. This was a challenging position at which for ISEA to arrive, but ultimately we believe this sends an appropriate marginal signal regarding the utilisation of available network for new generation development.
- ISEA supports downward redispatch for curtailment being non-market based for new renewables, given the likely market power concentration that would occur for new renewables were it to be classified as market based.
- The SEMC's position on non-participant generation needs to be revisited.
- We believe an evolutionary process should be taken with the market design up to the reintegration with European markets via the Celtic Interconnector. Care must be taken not to put unreasonable requirements – in terms of cost or procedural overhead – on generators, particularly those currently in development and de minimis generators. Market systems should be cognisant of variable renewable generators' technical characteristics, and not inadvertently result in downward redispatch of otherwise available renewable power willing, trying, and technically available to generate.

In particular, ISEA members strongly emphasise the need to have policy certainty – and where possible technical certainty – in a timely manner for participation in the RESS-2 auctions. Where further consultation on matters such as Bidding Principles or firm access policy is required, we recommend that inter-related decisions are made together, as industry will not be able to understand the impacts of proposals which are subject to future consultations. We suggest that all policy decisions and high-level understanding of the new scheduling arrangements should be completed by Q1 2022 at the very latest. As such, the SEMC proposed timelines cannot be allowed to slip.

1.2 STRUCTURE OF OUR RESPONSE

We have responded to both SEMC Papers together. We have cross-referenced particular sections of the SEMC Papers to which our consultation response relates.

Our response is set out in two thematic sections. The first section deals with **"Policy and Definitional Matters"**, i.e. the definitions of dispatch, redispatch, our position on whether they should be market or non-market based, and the appropriate level of compensation arising. This also deals with the related matters (as set out in the RA Letter) of market Bidding Principles[2] and - while outside the vires of the SEMC – the jurisdictional matter of connection policy and firm access.

The second section deals with "**Technical and Implementation Matters**", which are touched on in the Proposed Decision paper in particular. Following the TSO Workshop it is clear that it may be somewhat early to form an opinion on such detail, outside of some high-level principles. That said, ISEA does propose an evolutionary market roadmap over the coming years to integrate controllable variable renewable generation into the market design within the letter of the Regulation.

We address the proposals within the SEMC Papers individually in the last section, referencing back to the arguments made earlier in our response as appropriate.

We are happy to meet further with the Regulatory Authorities to discuss our position further.

[2] This catch-all term is used in our response to deal with both the Bidding Code of Practice (BCoP) and the Balancing Market Principles Code of Practice (BMPCoP) as applicable at any given time.

2 POLICY AND DEFINITIONAL MATTERS

2.1 SUMMARY POSITIONS

ISEA's position in relation to policy and definitional matters may be summarised as follows:

- ISEA believes that compensation for downward redispatch should be at the level of financial support, be it market-based compensation pursuant to Article 13(2) or non-market based pursuant to Article 13(7). We believe this is supported by a plain English understanding of the Regulation, and were this compensation not to be paid, this would be discriminatory relative to the design of conventional generation supports such as the Capacity Mechanism;
    - Such compensation rights should not be effectively undermined by restricting financially firm access (for market-based compensation) or guarantees for firm delivery of power (for non-market-based compensation) for generators. Such "firmness" should be sufficiently predictable to allow the formulation of firm corporate power purchase agreement (cPPA) and Renewable Energy Support Scheme (RESS) prices and offers.
    - For market-based compensation to be paid, this will require disapplication of Bidding Principles or a change to the allowed costs within those principles to include the level of financial support foregone.
- ISEA supports downward redispatch for constraints being market-based. We believe this sends an appropriate marginal signal regarding the utilisation of available network and disincentivises continued development in long-term constrained areas of the network. It is also within the spirit of the Regulation where redispatch should be market-based where possible. If the SEMC have concerns regarding market power behind constraints, Bidding Principles should be applied to decremental offers within the market (with the appropriate adjustments to allow compensation at the level of financial support).
- ISEA supports downward redispatch for curtailment being non-market based, at least on a transitional basis subject to material changes to the overall market design likely to be necessary later this decade. As Priority Dispatch generators' curtailment is non-market based (by definition), ISEA has fundamental concerns about the concentration of curtailment within a few market players (were it to be market-based for new renewables) leading to competition issues under Article 13(3)(c).
- Non-participant generators delegate their energy position to aggregators under the SEM design. As such, they do have an energy position and when constrained or curtailed, are redispatched within the meaning of the Regulation and are entitled to compensation.

These topics are discussed in greater detail below.

2.2 COMPENSATION AT THE LEVEL OF FINANCIAL SUPPORT

The SEMC have determined that non-market-based downward redispatch (curtailment) should only be compensated at the level of the day-ahead price for new renewables. Furthermore, compensation for market-based downward redispatch (constraint) should only be compensated under existing market rules.

ISEA believes that the SEMC analysis which has led to lower-than-the-level-of-financial support for non-market based redispatch is not in line with the Regulation's intent.

We are also fully of the view that the current treatment of compensation for market-based constraint is clear discriminatory treatment with respect to conventional generators and the protections afforded to them when equivalently redispatched under their own[3] State-Aid support scheme – the Capacity Remuneration Mechanism (CRM).

2.2.1 Non-Market Based Redispatch for Curtailment

The SEM Committee's rationale for reducing payment for curtailment[4] under the Regulation to levels below that of financial support all hinge on the application of the "unjustifiably high" test for the compensation under Article 13(7). The rationale given for Priority Dispatch generation and new renewables are different.

- Priority Dispatch generators are to receive no compensation, due to the value of that Priority Dispatch gives to the predictability of their investment cases in comparison to other classes of non-priority dispatch renewable generators;
- Overarching for both Priority Dispatch generators and new renewables, the level of curtailment in SEM is viewed as a special circumstance for our market, which – on a cost to the consumer argument – justifies not paying out at the full level of financial support.

Notwithstanding that ISEA are uncertain of the validity of the SEMC "comparative" test for Priority Dispatch generators as no such test is proposed by the Regulation, we would like to focus on the latter overarching cost-to-the-consumer argument and special circumstances of the level of curtailment in SEM.

ISEA understands that European Regulations need to be followed to the letter, rather than interpreted within the SEMC's national legislative objectives. The SEMC has relied on a recital to the Regulation to miscast the clear plain English intent of the Regulation. It is ISEA's understanding that recitals are useful for resolving intent where there is ambiguity in the Regulation, not to ignore provisions of the Regulation which a Member State may decide it does not like for internal policy reasons.

The plain English intent of the Regulation is clear. Unjustifiably high (or low) costs under Article 13(7) relates to unreasonable compensation paid on a short-run basis to generators which have been redispatched and have not been allowed to recover their loss arising. The examples given in the Regulation, for example, the requirement to compensate for the cost of back-up sources of heat when a HE CHP facility is dispatched down, or to pay for extra fuel costs when a generator is dispatched up, are at the generator level and have the clear intent to restore the generator to the same financial position as if the redispatch had not occurred.

[3] The Capacity Remuneration Mechanism is open to all classes of generators. It is, however, a support designed with conventional generation capacity margin in mind. Allowed bidding prices are based around conventional technology, and there are protections integrated into the Trading & Settlement Code when generators are redispatched.

[4] ISEA agrees this is non-market based downward redispatch. See Section 2.2.5.

The "unjustifiably high" test occurs not on a market-wide level, but for example where the higher of the components of the compensation (fuel costs, day-ahead price with financial support) are unjustifiably high. For example, if a non-subsidised generator with no intention of running was non-market redispatched on, and the Day-Ahead Price was far in excess of its fuel costs, a Regulator may infer that those revenues are "unjustifiably high" as the generator would not have otherwise earned such rent. The generator should only recover its costs to bring it to the same position, were it not for the redispatch.

It cannot be reasonably considered an "unjustifiably high" compensation for a new renewable generator subject to curtailment to be brought back to a financially neutral position, were it not for the redispatch.

Finally, the SEM Committee, while paying compensation at the Day-Ahead price for new renewable generators for curtailment, argue that the high levels of curtailment justify not paying at the full level of financial support. This is not supported by the Regulation. The definition of redispatching under the Regulation is (emphasis added):

> *"means a measure, including curtailment[5], that is activated by one or more transmission system operators or distribution system operators by altering the generation, load pattern, or both, in order to change physical flows in the electricity system and relieve a physical congestion* ***or otherwise ensure system security****"*

The Regulation does not allow the SEMC to make any such distinction between compensation payable for congestion or curtailment when applying the "unjustifiably high" test.

In short, non-market based redispatch should be paid at the level of financial support, and ISEA does not find the evolution of the SEMC's thinking in this matter since the proposals in SEM-20-028 in anyways valid or convincing.

2.2.2 Market Based Redispatch for Constraint (and Bidding Principles)

The SEMC proposes to use the standard T&SC-based[6] regime for compensation for market-based[7] redispatch. This would – under the current Bidding Principles – only allow non-synchronous renewable generators to retain the level of compensation achieved through ex ante trades. In ISEA's view this compensation regime is inappropriately low, leading to material investment uncertainty for new renewables, and is discriminatory when compared to the market-integrated State-Aid approved subsidy for conventional generation: the Capacity Renumeration Mechanism.

The Capacity Remuneration Mechanism (CRM) is a State-Aid delivery-based mechanism designed to support investment to ensure security of supply. It is the main mechanism through which new entrant conventional generators support their business case for long-term investment. Even if a generator

[5] "Curtailment" is not defined in the Regulation and is typically used for reduction of Interconnector or cross-zonal capacities. Hence, ISEA believes that the "otherwise ensure system security" is the more appropriate reference to SEM-colloquial curtailment.
[6] This is referred to as the "T&SC-based" regime, as in certain places in the SEMC Papers, the Trading & Settlement Code rules are proposed to be used for both market-based and non-market based downwards redispatch compensation.
[7] ISEA agrees with the SEMC that constraint should be considered market based. See later.

fails to deliver due to being redispatched downwards on a market basis, the generator does not face any penalty under the CRM and payments are not reduced. These protections are inbuilt into the T&SC, which manage the settlement of the CRM.

In comparison, renewable subsidies schemes such as RESS (and REFIT and ROCs) are State Aid delivery-based mechanisms designed to support investment to support decarbonisation. It is the main mechanism through which new entrant renewable generators support their business case for long-term investment. In that regard, renewable support schemes are a justifiable analogue to the CRM for conventional generators.

In contrast, however, if a renewable generator fails to deliver due to being redispatched downwards on a market basis, the generators face loss of subsidised revenues. This lack of full compensation arises from the combination of the T&SC rules and the Bidding Principles, both of which it is in the SEMC's gift to change. This is clear discrimination relative to the protections afforded to conventional generators under the CRM.

2.2.2.1 Bidding Principles

The current Bidding Principles are constructed on the basis that generators would seek to recover the difference in the marginal cost of production of energy when dispatched away from their market position, and that in turn is a solid proxy for a competitive market outcome. That assumption does not hold for renewable generators, which rely on delivery-based subsidy incentives, and in a competitive market would include the value of their lost subsidy in their offer. Application of the Bidding Principles which denies renewable generators the ability to recover their true opportunity costs results in a distorted representation of what the market's competitive outcome would have been, were there sufficient competition.

To that end, ISEA welcomes reference within the SEMC Letter as to a review of the Bidding Principles. We believe that either:

- The Bidding Principles need to change to reflect the efficient market outcome that would arise – renewable generators bidding decremental prices to recover their level of financial support; or
- Where the SEMC is satisfied there is sufficient competition amongst generators in the resolution of a constraint, disapplication of the Bidding Principles from renewable generators entirely.

ISEA recommends that making a decision on the matters raised in SEM-21-026 and SEM-21-027 without concluding this review of the Bidding Principles, leaves market participants unable to assess SEMC proposals, and at worst, in a position where certain SEMC proposals might be supported in the anticipation that the necessary Bidding Principles changes were forthcoming, only for those changes not to be made.

As a result, ISEA recommends either bringing the matters in SEM-21-026 and SEM-21-027 to a proposed decision, with a consultative section of Bidding Principles, or delaying a final decision until a separate consultation process is raised on what costs are recoverable for market-based redispatch of renewables supported by subsidy regimes.

ISEA have similar concerns and recommendations around the treatment of the meaning of "firmness" on jurisdictional basis.

2.2.3 Firm Access Policy

Financially firm access is required for compensation at a generator's decremental offer within the T&SC for market-based redispatch. A connection agreement which guarantees firm delivery of power is required for compensation for non-market based redispatch under Article 13(7) of the Regulation.

Clearly, jurisdictional firm access policy is a highly relevant factor for new generators managing the risk of downwards redispatch when making investment decisions. A new generator with the appropriate firmness can be confident of recovering compensation at the level of financial support (as appropriate by ISEA's analysis) or the day-ahead price achieved (under the SEMC proposals). In Ireland and Northern Ireland, however, the predictability of firmness has been poor.

- Some generators become firm close to their projected dates.
- In some cases, descoping of deemed unrequired infrastructure e.g. the 400kV reinforcement from the South-West to the East, has accelerated firmness.
- Too often, however, where firmness has been associated with large infrastructure projects (North-South Interconnector) or difficult and dynamically changing transmission issues (North Connaught and the North-West corridor), projected firm access dates can slip by many years.

Where generators:

- are exposed to unpredictable levels of downward redispatch;
- the date when compensation becomes payable is subject to material revision; and
- these risks are to be assessed at a single point in time (cPPA agreement, RESS auction, etc.)

this leads to a very unpredictable range of projected revenues. Even where generators have been provided with information that they are in a "good" location, i.e. will become firm shortly, they cannot reflect that signal in cPPA prices or RESS auction offers with any confidence. The signal for new generators to connect in stronger areas of the grid is muted by the uncertainty.

ISEA therefore calls for greater certainty in the timeframe for delivery of "firmness" within its various meanings for market-based and non-market based redispatch.

To that end, the ISEA requests that the SEM Committee liaise closely with the individual Regulatory Authorities to specifically examine the impact of "firmness" uncertainty on the investment necessary to achieve the jurisdictional decarbonisation agendas. ISEA believes that parallel consultations on this matter are required alongside the determination of the final decision in relation to the matters in SEM-21-026 and SEM-21-027. This consultation should include:

- The appropriate meaning of "firmness" within market-based and non-market-based concepts;
- The process for the allocation and calculation of available firmness – different planning standards may be appropriate for renewable generators;
- Consideration of the application of "firmness" to existing firm and non-firm projects;
- Consideration of other non-network solutions which can help mitigate any delays in associated transmission reinforcement completion; and

- Critically to provide certainty for investing generators, binding dates for application of firm access with new connection offers.

The firm access methodologies used by SONI and EirGrid should then be updated to reflect this final policy. We note that the ECP2.1 decision requires EirGrid to finalise methodology by mid-2021 so consultation is immediately required to ensure that EirGrid workstream is not delayed, creating a misalignment with the RESS-2 auction timeframes.

2.2.4 Non-Participant Generation

"The RAs do not consider that such units are subject to redispatch, as they are not moved from a market position within the SEM."

The above quote is in relation to non-participant (de minimis) generators. ISEA would like to point out to the SEMC that the assertion that non-participant generators do not have an energy position is directly contrary to a conclusion made by the SEMC just over a year ago in SEM-20-027, dealing with the matter of Balance Responsibility. They have delegated the management of that energy position to an aggregator (emphasis added in quotation).

"De minimis generation can seek intermediary arrangements with supplier units, assetless units, or even DSUs or AGUs for the purpose of settling their imbalances in the market. These units then pool the de minimis generation loads (if there is more than one de minimis generator in contract with the unit) in ***order to determine the position, they will be taking in the ex-ante and balancing markets****."*

Supplier Units (or assetless units or AGUs) take energy positions on behalf of their contracted non-participant generators. In that manner, Supplier Units become balance responsible for their non-participant generators. When those generators are dispatched down by the TSO, the Supplier Unit experiences the resulting imbalance. Whether the energy position is delegated to a different Balance Responsible Party is irrelevant – the non-participant generators have an energy position.

It is unclear whether the SEMC is genuinely suggesting that a controllable non-participant non-priority dispatch generator cannot deliver energy, i.e. does not have an energy position, unless it becomes a market participant. Taking that position to its logical conclusion with the example of a 5MW solar farm:

- That generator would need to become a full market participant; and
- It would need a unique registration in the ex-ante markets in order to achieve a uniquely traded position.

ISEA estimates that the market registration costs alone of such a trading arrangement for a 5MW solar farm would be well in excess of €1/MWh, just for access to the trading structure (which still has to be operated at further cost) for the right to be dispatched to deliver energy. It would also create extraordinary administrative overheads for these generators relative to European norms.

ISEA is firmly of the view that this assessment of de minimis generators is plainly incorrect. This also has perverse outcomes for compensation for redispatch. At its simplest, this requires a generator to become a market participant in order to be compensated for non-market based redispatch.

ISEA has various proposals – in line with the original ISEM design principles – within the Technical and Implementation Matters section to resolve this completely unreasonable position.

2.3 CONSTRAINT AS MARKET-BASED REDISPATCH

ISEA support the SEMC's position that constraint is non-market based redispatch for new renewables without Priority Dispatch. It agrees with the broad principles set out in Article 13(1) that redispatching should be market-based where possible. This clause should be the starting position.

Article 13(2) states that such redispatching should be compensated. Our interpretation of the necessary levels of compensation for market-based redispatch are set out in Section 2.2 above. It is questionable whether a redispatch action can be considered market-based, if it is not compensated adequately.

Article 13(3), however, cannot be ignored. It sets out two scenarios in Article 13(c) and (d) where market based redispatching might not be appropriate and non-market based redispatching is allowable. Both scenarios relate to the exercise of market power, where constraints can only be resolved by a limited number of parties.

In ISEA's opinion, the SEMC under such circumstances where there is a concern regarding market power, can apply Bidding Principles to ensure an efficient market outcome, as is done in general for constraints for large conventional generators today. Our view on the necessary adjustment to the Bidding Principles is set out in Section 2.2.2.1 above.

It should be noted that this particular aspect of the Regulation caused the most difficulty in reaching consensus within ISEA. Ultimately this position was carried by majority vote at the Board, and there will be ISEA members who disagree with this position which emphasises how potentially contentious this topic is, and that there are legitimate differences of interpretation and opinion on the impact of the SEMC's proposals. This situation highlights the need for there to be utter clarity on the implications of the final decision for the market.

Decisions need to be complete, timely and clear, particularly within the context of RESS auctions which have introduced pay-as-bid competitive renewable support which rely on such regulatory certainty.

Swaying the argument in favour of treating constraints as market based were that (a non-exhaustive list):

- It is the requirement of the Regulation that redispatch be market-based where possible, and a market-based solution (with appropriate Bidding Principles applying as necessary) is indeed possible. It is ISEA's position in relation to the Regulation that it should be followed to the letter – and this applies to our arguments above for compensation for downward redispatch as well;
- There should be stronger signals for generation that utilise available network, rather than diluting the impact for generators which contribute materially to increases in constraints on the margin. Indicative analyses show that solar generation can connect to network which is lightly constrained with other renewable generation (often at night-time) with no overall increase in its own constraints. Where the connecting generators face the issues to which it itself contributes, this sends an appropriate signal which will be reflected in the competitiveness of, for example, RESS auction prices.

There were arguments to the contrary. For example (again not exhaustive):

- High impact, low probability events (such as a transmission outage) can be more severe where priority dispatch generation is grandfathered for constraints (i.e. it is non-market based) and new renewables are dispatched down first. Nevertheless, indicative analysis indicates that treating all constraints as non-market basis would still be problematic (albeit at a lower level) during such an event.
- Available analyses from the TSO have been based on pro-rata constraints to date, and this may trigger new analyses for generators in constrained regions. ISEA therefore requests that future analyses provided by the TSO, however, should be provided in line with the SEMC's ultimate decision.

On balance, however, the ISEA Board determined that in a resource constrained world, it is appropriate that signals are sent to invest in the most appropriate areas of the network and technologies to support the decarbonisation agenda as efficiently as possible.

We acknowledge that over time within the context of our existing market design, this could increase long-term volatility for all new renewable generation investment, but this must be assessed within the context of an ambitious decarbonisation agenda in Ireland and Northern Ireland which is going to have to deal with energy pricing driven by higher and higher levels of non-synchronous renewables, and material periods of over-supply of renewable generation in order to meet targets. Volatility in constraint projections will be just one of the matters to be resolved.

The evolution of the market design is discussed further in the next Section.

2.4 CURTAILMENT AS NON-MARKET-BASED REDISPATCH

ISEA agrees with the SEMC's analysis that curtailment should be non-market based. Redispatch of Priority Dispatch generation is by definition non-market based. Redispatch of new renewable generation for curtailment on a market basis in advance of non-market-based resources clearly creates material market power issues until the level of curtailment reduces, the installed MW of renewable generation increases, or both. These market power issues trigger Article 13(3)(c), allowing curtailment to be classified appropriately as non-market based.

Over time, perhaps within the context of a fundamental market redesign alluded to above and discussed further in the next Section, it may be possible to consider curtailment as market based. At this moment in time, however, given the scale of the redispatch and the limited number of market based resources to fulfil the redispatch, it is not prudent to consider it anything other than non-market based.

3 TECHNICAL AND IMPLEMENTATION MATTERS

3.1 SUMMARY POSITIONS

ISEA has three key technical implementation requests:

- No changes should be made to existing scheduling and dispatch (with the exception of a detailed matter on the management of constraints discussed later) until a more mature solution is designed and delivered. We estimate the delivery of such a solution to be in 2024 (called Phase 2 in this paper);
    - This does not mean granting new renewables Priority Dispatch or seeking to revisit the decisions of SEM-20-072, but rather allowing such generators the temporary right to opt out from mandatory Balancing Market participation until the new scheduling and dispatch regime is in place.
- This Phase 2 solution should include appropriate portfolio trading of renewables, which has been a non-delivered requirement of the High-Level Design of the I-SEM since 2014[8]. Portfolio trading should also facilitate the dispatch, scheduling and compensation for redispatch of non-participant generation without requiring those generators to become market participants.
    - The nature of the dispatch and scheduling in this Phase 2 should reflect solar and wind's technical characteristics, with a view to minimising the downward redispatch of such generators inadvertently arising through procedural issues;
- An out-of-market system should be used for the payment of compensation for downwards redispatch both retrospectively and on an ongoing basis until the market reintegrates with the European market (called Phase 3 in this paper). This system can provide compensation in excess of market revenues as necessary for all classes of eligible generator under the Regulation (participant and non-participant / priority dispatch and non-priority dispatch).
    - ISEA believes this has many potential benefits, including faster implementation, flexibility to implement non-market compensation without impacting existing wider market policy (Trading & Settlement Code (T&SC), bidding principles, and potentially even firm access policy).

The overall development "roadmap" is set out in Figure 1.

[8] Integrated Single Electricity Market (I-SEM): SEM Committee Decision on High Level Design

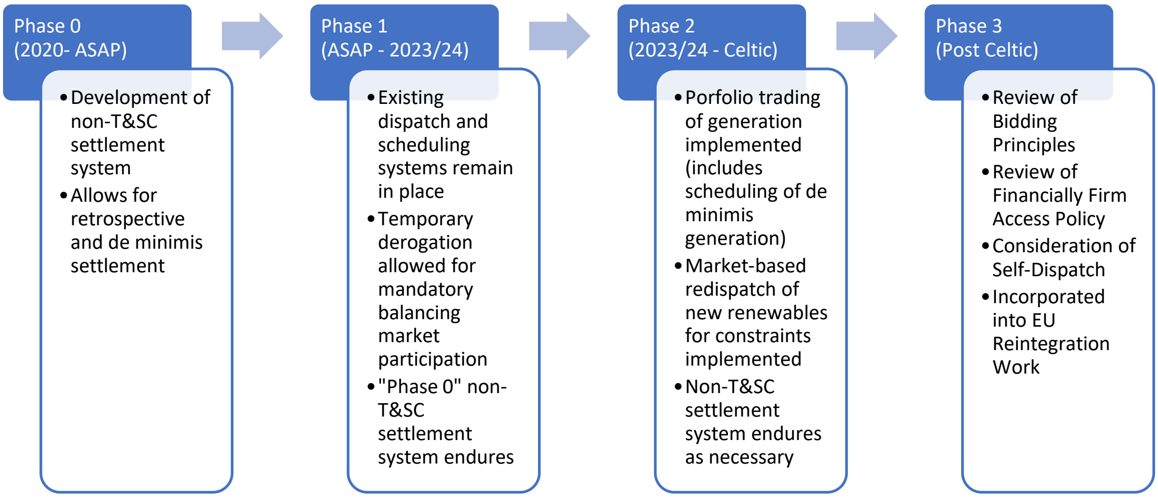

Figure 1. ISEA Proposed Technical Development of the Market

Practical and legal justifications for these positions are provided below. In particular, ISEA urges the SEMC to consider how de minimis generators will be treated equitably (without incurring undue costs) during each phase of the market design.

Transitional systems are likely to be imperfect, and in that imperfection are likely to trade one requirement of the Clean Energy Package (e.g. non-facilitation of aggregation, discrimination against technology types, introducing unnecessary downwards redispatch of renewables) against the key focus of the SEMC Papers: removal of Priority Dispatch and implementation of Article 13 compensation.

ISEA of course welcomes the possibility of a perfect solution, implemented expediently. We did not gain confidence, however, following the TSO Workshop of the 1st of July that such a solution to manage non-priority dispatch renewables would be imminently forthcoming.

The SEM Committee has a clear choice during this transitional period: to implement the loss of Priority Dispatch as a matter of urgency, or to ensure that the transition to non-Priority Dispatch renewables is done in a predictable, fair manner minimising the impact on project development and the continued trajectory to renewable targets in Ireland and Northern Ireland (noting that the incremental effect to existing Priority Dispatch generation during such a transitional period is likely to be low).

ISEA strongly advocates for a fair, predictable transition. We have set out one potential example of such a transition in Figure 1. This is discussed in more detail in Section 3.2, touching on several detailed matters in the SEMC Papers throughout.

Again, we urge that high-level clarity is given to market participants by Q1 2022 at the latest, to give clarity on the risks and features of the market design when participating in future RESS auctions.

3.2 TRANSITIONING MARKET DESIGN IN COMPLIANCE WITH APPLICABLE LEGISLATION

ISEA welcomes the TSO workshop given on the 1st of July during the consultation window. We fully support such ongoing engagement and will endeavour to contribute in a constructive manner as such opportunities arise.

It is clear that there will be implementation challenges for the TSO to deliver any solution where large numbers of price-responsive new units are brought under the central dispatch paradigm. The compromises and design choices presented at that workshop were a reflection of those within the central market systems. These are only a portion, however, of the compromises that need to be considered.

ISEA wishes to take this opportunity to provide our own high level impact assessments on our members of potential various solutions to integrate non-priority dispatch renewables at scale in the Single Electricity Market. The technical compromises that must be made to deliver interim and enduring solutions are not to be found only within the System Operator but should be evaluated across the industry. These compromises cannot be made without due regard for the ongoing legal obligations, and the overall impact on the renewables industry as a whole where some non-compliance is necessary on a transitional basis.

We support an evolutionary process for such changes. We highlight that as certain elements of our market design evolve in parallel with the technical solutions to remain efficient and non-discriminatory, there are legal requirements that cannot be ignored.

We draw attention to paragraph A.2.1.4 (a) and (f) of the SEM T&SC, which seeks:

"(a) to facilitate the efficient discharge by the Market Operator of the obligations imposed upon it by its Market Operator Licences;

(f) to ensure no undue discrimination between persons who are parties to the Code;"

and also to Article 6(1) of the Regulation which states that Balancing Market should:

"ensure effective non-discrimination between market participants taking account of the different technical needs of the electricity system and the different technical capabilities of generation sources, energy storage and demand response;"

These are important legal requirements to keep in mind during the evolution of market changes. There is no point in meeting the requirements of one part of the Regulation (i.e. treatment of controllable variable renewables without Priority Dispatch) if the interim systems are in clear breach of parts of the Regulation (e.g. not taking account the technical characteristics of the generators) or the principles of the T&SC if it results in inefficient discharge of its functions (requiring hundreds of small generators to become participants only in order to have the right to generate power).

3.3 A PHASED APPROACH TO MARKET EVOLUTION UNTIL EUROPEAN MARKET RECOUPLING

First, ISEA would like to set out some definitions to ensure that there is clarity on the points to follow.

On review of the SEMC's Papers, and the TSO Workshop, ISEA believes that there are three potential phases of market / scheduling design to give effect to the Clean Energy Package's requirements for non-priority dispatch renewables. We also note the existence of a "Phase Zero", which is currently in effect.

Phase Zero: This period describes the time between the coming into force of the Regulation and the implementation of the first transitional systems to start implementing the Regulation.

Phase 1: This period reflects the transitional arrangements until more robust technical solutions can be put in place. This is the solution in the SEMC Papers slated to be operational within 36 months of the SEMC decision.

Phase 2: This medium-term solution, perhaps integrated with the Future Arrangements for System Services, will endure at least until the reintegration with the full European markets. During this time the number of generators subject to central dispatch is likely to grow materially, putting pressure on central dispatch and scheduling systems.

Phase 3: This represents a more fundamental redesign of the market, a full reintegration with the European arrangements on the delivery of the Celtic Interconnector (see ACER Decision 08-2021). By that time, if Ireland and Northern Ireland are making steady progress towards 2030 electricity decarbonisation objectives, we will continue to have world-leading renewable integration from non-synchronous sources in the Single Electricity Market, with the associated challenges that entails.

These Phases are discussed in turn. We reference particular sections of the SEMC Papers where our comments have specific relevance.

3.3.1 Phase Zero: The Period of Non-Compliance, Retrospective Payment

We welcome the SEM Committee's acceptance that irrespective of the status of the central market and dispatch systems, EU/2019/943 became legally binding from the 1st of January 2020. It is difficult to assess the two different presented options in the Consultation without further detail (e.g. the final downward redispatch compensation rules), but we suggest the following principles apply:

- Generators should be settled individually based on the delta between received market compensation and the level of revenues that the generator would have received, had the Regulation been in effect. This may also include adjustments to market-based compensation for constraints, if necessary; and
- Generators should not be penalised for lost revenues arising from trading rules or registration requirements necessary for the ongoing receipt of such compensation, which are made known retrospectively.

As the T&SC does not facilitate retrospective changes to market rules, ISEA are firmly of the view that this settlement solution will need to be operated outside of the T&SC governance and systems. There are further advantages to this, which are:

- This non-T&SC solution means that the funding of compensation at the level of financial support can be jurisdictional in nature, ensuring Northern Ireland and Ireland places the cost of jurisdictional support schemes on the consumers which benefit.
- De minimis generation may also be able to receive the compensation that they are due under the Regulation. (Article 13(7) does not state that a generator must be a market participant to receive compensation at the level of financial support nor does Article 12 state that a generator must itself be a market participant to have an energy position).

- It allows, until T&SC systems are implemented for market-based redispatch (along with the necessary changes to Bidding Principles), the ability to supplement T&SC-based compensation (up to the level required by the Regulation) until Phase 2 arrangements are in place.
- It also allows for non-market-based compensation to be made on the basis of a connection agreement with the "firm delivery of power", which can be decoupled from the current concept of financially firm access within the market, if deemed appropriate to do so.

ISEA recommends that this Phase 0 settlement system is implemented as soon as possible. We believe that it will be the settlement process of choice up until and including Phase 2 for non-market based redispatch and for de minimis generation.

3.3.2 Phase 1: The Short-Term Solution for New Connecting Generation

It should come as welcome information and no surprise that new renewable generators – in particular solar generation under RESS-1 – are signing contracts and are proceeding to construction despite the uncertainty in the regulatory environment. Developers are procuring generators, control systems and TSO interfaces based on the existing standards which are known today. If these interfaces and standards are to change in the very short term, pragmatically speaking ISEA cannot see how either new generators or priority dispatch generators can both have their rights fully protected under those timeframes. Either:

- New generators will be pushed into an unsuitable regime which discriminates against them in terms of their technical characteristics and possibly dispatches them at an inappropriate level. Examples of this would be shoe-horning new renewable variable generators to interface with EDIL as dispatchable units on an interim basis, dealing with MW-to-MW second-by-second dispatch instructions and declarations, requiring de minims generators to become full market participants without any facilitator to aggregate their route-to-market solutions, etc.; or
- Priority Dispatch generators will be required to share their more favourable dispatch and scheduling rights on an interim basis until the "Phase 2" solution can be delivered, i.e. new renewables will be treated under existing market systems and will be dispatched equivalently until new solutions are delivered. ISEA believe that this can be facilitated in principle by temporarily removing the obligation of generators to act as Balancing Service Providers until Phase 2 is delivered. For the avoidance of doubt, these generators would remain Balance Responsible during this period.
    - This could be facilitated by the TSO maintaining SCADA control through the EMS Dispatch Tool as per normal, all participant generators registering as "Autonomous" in the market and being compensated as appropriate through the non-T&SC market system for redispatch as required.
    - For the avoidance of doubt, this is not trying to grant Priority Dispatch to new renewables through the back-door in perpetuity. It is a temporary compromise which reflects that sudden changes (which would be supplanted by further "Phase 2" solutions) that require material changes to in-development generators are simply unfair. The transition to non-priority dispatch should be managed in a fair, predictable manner.

- Avoidance of material changes in Phase 1 (outside of the development of the non-T&SC compensation mechanism) also allocates scarce resource towards the delivery of Phase 2.

At the moment, the Single Electricity Market is not compliant with the Regulation. It is almost certain that it will remain non-compliant in material aspects until Phase 2 is delivered. The TSO workshop of the 1st of July gave no comfort that this would not be the case.

At this moment, it is appropriate that the SEM Committee decide on the "least harm" form of Regulation non-compliance until an enduring solution can be rectified. Given the relative scale of existing Priority Dispatch generators to the scale of new renewables which are likely to be connected prior to the delivery of Phase 2, and the damage to investors' confidence that disruption to the first tranche of new renewables operational under the new Regulation would cause, ISEA strongly recommends that material changes to scheduling and dispatch should be descoped from Phase 1.

There is one exception to this, however. Solar is unjustly treated by the current constraint management methodology[9] within constraint groups. Generators are pegged at their level of output when constraints commence and are controlled down from that that level on a percentage basis until the constraint is no longer binding. As wind generators cause constraint often at night, this leads to solar generators being pegged at zero production when the constraint becomes binding, and being held to zero production until the constraint is resolved while other generators remain able to partially generate[10].

In plain English, this means that when the sun comes up in the morning, the TSO will continue to dispatch the solar generator at a percentage of its night-time power, i.e. at zero, until the constraint no longer applies.

The application of this process needs to be confirmed, clarified and where necessary rectified. This analysis needs to be performed on a transitional basis (until the delivery of Phase 2) and how this will be managed under a market-based solution.

Generators that do not qualify for priority dispatch should interface with existing market systems and processes (SCADA), and transition over to the new systems in Phase 2 in 2023/24 when they are robust and operational.

This principle also applies to any changes required under the T&SC for downwards redispatch compensation for new or priority dispatch renewable generators. The Market Operator should not accrue and retain money which could otherwise be distributed to those who are entitled to it.

To that end, ISEA recommends that all redispatch compensation (in excess of that paid under existing market rules) is paid during Phase 1 from a non-T&SC system. ISEA contends that the Phase 0

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[9] https://www.cru.ie/wp-content/uploads/2016/07/SEM13011-TSOs-Definition-of-Curtailment-and-Constraint.pdf

[10] https://www.sem-o.com/documents/general-publications/Wind_Dispatch_Tool_Constraint_Groups.pdf states: *"…constraint is applied in proportion to the active power output of each wind/solar farm which, for the initial application of the constraint, is also equal to the available active power of each wind/solar farm. If the wind/solar farms are further dispatched down as the constraint/curtailment becomes worse this will always be pro-rata based on the wind/solar farm actual output* ***and does not consider the changing availability*** *of the wind/solar farm."*

retrospective settlement system could be easily repurposed for such purposes. Indeed, ISEA believes that the Phase 0 retrospective settlement system is the appropriate system for delivering non-market compensation to generators until Phase 3 is delivered.

3.3.3 Phase 2: Enduring Solution Prior to European Reintegration

This description of Phase 2 (and the rationale for the proposals below) is based on the assumptions that the core elements of the ISEM design remain unchanged.

- Central dispatch;
- Ex ante markets remaining the exclusive route to physical dispatch with some pragmatic flexibility around final physical notifications for renewables and conventional generation;
- Mandatory participation in the Balancing Mechanism as a Balancing Service Provider;
- An ex ante market position required to demonstrate an energy position, i.e. the energy dispatch from which can be compensated when financially firm; and
- Bidding code of practice applicable to system (non-energy) actions.

Phase 2 sees a further incremental evolution of market principles and systems by this time, including:

1. Portfolio trading, as required per SEM-14-085a, the ISEM High Level Design. We note that the Regulation also requires facilitation of aggregation. Article 6(1)(c) states:

   "1. Balancing markets, including prequalification processes, shall be organised in such a way as to:

   …

   (c) ensure non-discriminatory access to all market participants, individually or through aggregation, including for electricity generated from variable renewable energy sources, demand response and energy storage;"

   This would allow a trader to take an ex-ante portfolio position and allocate that trade (via Physical Notification or otherwise) to the generators for which it is managing balancing responsibility. Those trade allocations disaggregated from a single portfolio will allow generators – both participants and non-participants[11] – to be scheduled for dispatch and with that energy position, be therefore eligible for compensation for redispatch. This is related to the concept of "Biased Quantities" discussed in Section 2.2 of the Proposed Decision.

2. Market-based downward redispatch for renewable generation without Priority Dispatch should be implemented under Phase 2. This will also allow time for changes to either the application of Bidding Principles or the Bidding Principles themselves in order to allow recovery of the full costs of redispatch at the level of financial support (as determined by market competition, or regulated via Bidding Principles).

[11] The allocation of the SEMOpx ex ante trade could be made to T&SC registered generators and to generators which are outside of the T&SC.

3. A further piece for consideration at this point in Phase 2 will allow control of variable renewable generation not via EDIL, but via the existing SCADA control systems. It is simply not appropriate for hundreds of renewable generators to take manual dispatch instructions from the National Control Centre. Even in the event where EDIL could be automated, its integer MW dispatch set points are inappropriate for variable renewables. Furthermore, TSO forecast errors (perhaps informed by trader forecast errors in their submission of Physical Notifications) may also inadvertently lead to renewable generators being subject to unnecessary downwards redispatch, which is contrary to Article 13(5) of the Regulation which states:

   "…regulatory authorities, transmission system operators and distribution system operators shall… 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"

   ISEA continue to contend that MW-by-MW dispatch instructions are designed for predictable conventional generation, and to issue such instructions to variable renewable generators would be discriminatory and contrary to Article 6(1) of the Regulation, which states that the Balancing Market shall:

   "ensure effective non-discrimination between market participants taking account of the different technical needs of the electricity system and the different technical capabilities of generation sources, energy storage and demand response".

   In general, where renewable power is willing and trying to generate, and where such power can be accepted by the Grid, it should be taken. Not to do so undermines the maximisation of power from renewable sources, impacting renewable targets and increasing costs of competitive subsidies and cPPAs.

   In summary, notifications from Traders and Dispatch Instructions from the TSO should be one of the following forms: generate at full resource availability, or stay at or below X MW, where X MW is below the current resource availability.

   As per the SEM Committee's discussion, this should remove issues suggested with Uninstructed Imbalances (which would also arise under an EDIL-based system).

3.3.4 Phase 3: Market-Based European Market Integration

By 2027, the Single Electricity Market will need to reintegrate with the wider European Market arrangements. Hundreds of new dispatchable non-priority dispatch renewables ranging in size from sub 5MW solar to new commissioned offshore windfarms are likely to be operation at this stage. In the absence of portfolio trading in ex ante markets, note the number of trading units registered individually in SEMOpx needed to facilitate each generators' dispatch (and redispatch compensation) will be material.

Central dispatch systems will unlikely be able to cope with the complexities of the scheduling and dispatch problems to be solved.

The paradigms of the market are likely to change materially at this point. Energy pricing will likely to be eroded as an investment signal given the prevalence of non-synchronous zero marginal cost energy, often in excess of required demand and Interconnector export. System services, capacity market revenues, and subsidies will likely drive the ongoing transition to a decarbonised electricity market.

The capability of the network (from a congestion point of view) will need to be more aggressively optimised (e.g. different non-correlated renewables sharing the same grid capacity on a “firm” basis), and sufficient certainty around the rights of compensation for redispatch will be required.

The 2030 decarbonisation agenda in Ireland and Northern Ireland is therefore likely to trigger a necessary revolution in SEM trading arrangements and connection policy (rather than the evolutionary process proposed here up to the integration of the Celtic Interconnector). These changes are likely to go necessarily beyond the requirements of the Clean Energy Package.

ISEA believes that while it is too early to confirm when and if that revolutionary market change will be required, it is useful during the interim period of evolutionary change (Phase 0, Phase 1, Phase 2) that alterations and improvements to the existing market design keeps an eye on potential future market requirements where possible.

4 RESPONSE TO INDIVIDUAL SEM PAPER PROPOSALS

4.1 CONSULTATION SEM-21-026

4.1.1 Definition of Dispatch and Redispatch

- *“In the SEM, dispatch relates to the scheduling and dispatch of units to meet the energy requirements of the market, noting the complexity of identifying dispatch and redispatch separately in the central dispatch system with an integrated scheduling process, which is carried out through the identification of energy and non-energy actions as part of the flagging and tagging process.”*

ISEA agrees with this assessment.

- *“Energy balancing in the SEM aligns with the definition under the Electricity Balancing Guideline as ‘energy used by TSOs to perform balancing and provided by a balancing service provider. Dispatch and energy balancing are aligned to the existing concept of ‘energy actions’ in the SEM.”*

ISEA agrees with this assessment.

- *“A complexity to this interpretation is that priority dispatch wind and solar units cannot be dispatched for energy balancing purposes. This issue is considered further in Section 2.1 and updates may be required to SEM-13-011 in terms of the distinction between constraints, curtailment and energy balancing. This issue is also considered in the SEM Committee’s Proposed Decision Paper on the treatment of new renewable units in the SEM (SEM-21-027), which has been published along with this paper.”*

ISEA notes that dispatchable priority dispatch renewable generators can be used for energy balancing. We are uncertain that where, for instance, a priority dispatch renewable generator chooses not to produce power (for example, due to unfavourable market prices below its cost of production), and the TSO decides to dispatch that generator up to meet an energy need, for instance, why that would not be considered energy balancing. Priority dispatch for wind and solar units may currently be implemented as a form of "mandatory dispatch" in the SEM today, but that is a restriction of the implemented dispatch and scheduling tools, and no other dispatchable renewable generator with Priority Dispatch is treated in that manner.

- *"Redispatch in the SEM relates to deviations from the market schedule for generation for both local network and broader system reasons, including TSO-instructed reduction in generation due to localised network issues (constraints) and reduction in non-synchronous generation due to other system-wide reasons such as levels of System Non-Synchronous Penetration (curtailment)."*

ISEA agrees with types of actions which are considered as redispatch. There is a legitimate query, however, whether redispatch is from the market schedule (which we interpret to be the ex-ante market schedule), or from the "dispatch" which would reflect energy balancing actions and Priority Dispatch rights. This is an important clarification to consider, as:

- It appears to be contrary to the SEMC's definition of "dispatch" given above; and
- Priority Dispatch generators do not need a market position in order to have the right to be dispatched.

- *"The Regulatory Authorities acknowledge that future market developments may include new forms of dispatch and redispatch at the distribution level."*

ISEA supports this position. Whether a redispatch action arises from the DSO or TSO, it should be treated identically when it comes to the subsequent allowed compensation.

- *"As part of this Consultation, the Regulatory Authorities welcome feedback on whether decremental actions taken on priority dispatch units can be considered either dispatch and redispatch (energy and non-energy actions) or as forms of redispatch only (non-energy actions)."*

See above. ISEA believes that where actions are taken on any market unit, it can be considered an energy action. Indeed, in the rare event that there is oversupply of renewable Priority Dispatch generation relative to system demand, it is difficult to describe what the decremental actions taken on such generation could be other than energy actions (to the point where the delivered power was equal to system demand).

- *"As set out in the SEM Committee's Building Blocks Decision Paper (SEM-15-064), priority dispatch generation should not be able to set the imbalance price. In a situation where the sum of available priority dispatch renewable generation exceeds the demand to be served in a particular 5-minute period and all available non-priority dispatch units have been dispatched down to their Lower Operation Limit, priority dispatch units are dispatched down according to* *the priority dispatch hierarchy, one option is to reflect this by implementing a Modification to replace the decremental bids of such units with zero for Imbalance Pricing.*

Alternatively, it is proposed that a new flag for priority dispatch units could be introduced to the flagging and tagging process to ensure that in such instances, priority dispatch units are not price setting and are settled on the basis of their complex bids.

The interaction between this discussion and related Consultations on the Electricity Balancing Guideline and Articles 3, 6 and 10 of the Electricity Regulation has been discussed in this section and a decision on the Modification referenced here will not be taken until this suite of Consultation and decision-making processes are complete."

If ISEA's view above is correct that such actions on Priority Dispatch units (incremental or decremental, controllable or dispatchable), then it is difficult to see how the decision of SEM-15-064 can still hold in light of the subsequent EBGL and Clean Energy Package requirements. ISEA is currently agnostic on the form of implementation of any required modification until the policy position is determined.

4.1.2 Definition of Non-Market Based Redispatch

- *"Curtailment in the SEM is currently a form of non-market based redispatch, as it is applied to all non-synchronous units (regardless of priority dispatch status) and is not based on any merit order or the bids and offers of units."*

ISEA agrees with this position. We also note our comments above in Section 2.4.

- *"Constraints as applied to all non-priority dispatch units are a form of market based redispatch."*

ISEA agrees with this position. See our discussion above in Section 2.3.

- *"Constraints as applied to all priority dispatch units are a form of non-market based redispatch."*

ISEA agrees with this position.

- *"Constraints as applied to priority dispatch units and non-priority dispatch units should be remunerated based on the different mechanisms for compensation already in place in the SEM that are based on decremental prices submitted by non-priority dispatch units and the deemed decremental prices applied for priority dispatch units. The Regulatory Authorities do not propose any change to the current market mechanisms of remuneration for constraints."*

ISEA disagrees with the position for a number of reasons:

- Without review of firm access policy (see Section 2.2.3) and Bidding Principles (see Section 2.2.2.1), this leads to an unreasonably low and discriminatory level of compensation (see Section 2.2.2); and
- We believe a Non-Market Settlement System would be best place to compensate generators for market based redispatch for a transitional period and non-market based redispatch on an ensuring basis for the reasons given in Section 3.3.1 in particular).

4.1.3 Financial Compensation Under Article 13(7)

- *"The RAs recognise that the issue of the difference between the ex-ante market schedule and feasible dispatch requires further consideration. The RAs intend to further assess these issues as part of a range of measures being considered to mitigate curtailment in the SEM."*

ISEA welcomes further discussion in this regard, and notes that principles of non-discrimination along with the requirement to minimise downwards redispatch from generators which are able, trying and technically capable of delivering renewable energy. Please see our comments in Section 3.2.

- *"The RAs propose provide financial compensation for non-market based redispatch associated with curtailment based on a different compensation regime for priority dispatch and non-priority dispatch units. This is based on the value of priority dispatch and to provide a potential incentive for units to voluntarily give up priority dispatch, which may in turn reduce levels of curtailment where units are not run to their availability."*

ISEA disagrees with this position, as we do not believe it is compliant with the Regulation for the reasons set out in Section 2.2.

- *"Under this proposal, all units that are currently eligible for priority dispatch would receive compensation for non-market based redispatch (in relation to curtailment), where firm, up to the level of their additional operating costs caused by redispatching pursuant to Article 13(7) (a)."*

ISEA disagrees with this position. The compensation is not adequate. See Section 2.2.1.

- *"All new units, which are no longer eligible for priority dispatch, based on the criteria outlined in SEM-20-072, would be subject to compensation under Article 13(7), where firm and subject to non-market based redispatch (in relation to curtailment) up to the level of the DAM price at the time they are curtailed."*

ISEA disagrees with this position. The compensation is not adequate. See Section 2.2.1.

- *"All units would have the opportunity to avail of compensation up to the level of the DAM price in exchange for surrendering their priority dispatch rights. This is linked to the implementation of market changes to facilitate non-priority dispatch renewables set out in SEM-21-027."*

Given that curtailment is forecast to fall over time, to be replaced with competition for dispatch, and given the low incentive involved, ISEA does not believe this will result in material levels of existing generators foregoing Priority Dispatch. ISEA supports incentives for generators to give up Priority Dispatch, but for that incentive to be meaningful will probably require a review of Bidding Principles (to allow those generators to compete on price for constraint and curtailment) or some other compensatory mechanism.

- *"There are set targets in place to increase the level of SNSP to 75% by the end of 2021 and the TSOs plan to operate the system at SNSP levels of up to 95% in future in order to accommodate significantly higher levels of renewables. This may entail some enduring level of curtailment and a continued issue of alignment of the market with operational and system security requirements. On this basis, the RAs are also considering whether a limit on compensation under Article 13(7) could be included in future to account for the higher targets of SNSP and levels of non-synchronous generation which can be physically accommodated on the system."*

ISEA disagrees with such limits, as they are contrary to the letter of the Regulation. The SEMC simply cannot disapply European Law requirements. We also note that the "issue" of market misalignment with operational and system security requirements is nothing new, and it is a feature of any unconstrained market design. We cannot agree that using a natural feature of the agreed European ex ante market design (unconstrained ex ante market) as a rationale for refusing to implement other features of the agreed European ex post market design (compensation for redispatch) is in anyways correct or justified.

- *"The RAs are of the view that constraints applied to priority dispatch units and non-priority dispatch units should only be remunerated based on the mechanisms for compensation already in place in the SEM. Units which benefit from priority dispatch should not be overcompensated for the non-market based nature of constraints applied to them, which is driven by the way in which priority dispatch is implemented in the SEM."*

ISEA disagrees with the position for a number of reasons:

- Without review of firm access policy (see Section 2.2.3) and Bidding Principles (see Section 2.2.2.1), this leads to an unreasonably low and discriminatory level of compensation (see Section 2.2.2); and
- We believe a Non-Market Settlement System would be best place to compensate generators for market based redispatch for a transitional period and non-market based redispatch on an ensuring basis for the reasons given in Section 3.3.1 in particular).

As a general point, we disagree that non-participant generators need to become a market participant in order to receive compensation for redispatch.

- *"The RAs propose to only compensate firm generators for non-market based redispatch associated with curtailment."*

ISEA believes that the requirements of the Regulation should be implemented as a minimum. Consideration should be given as to the appropriateness (in terms of investment security) of further compensation mechanisms, should the associated risks of curtailment become unmanageable.

4.1.4 Application of Proposals from 1 January 2020

- *"The SEM Committee has outlined two proposals for an ex-post payment mechanism and welcomes feedback on this from interested stakeholders, including alternative proposals.*

> *It is expected that under either mechanism, no change would be required to the treatment of Curtailment within the Trading and Settlement Code."*

ISEA propose a Non-Market Settlement System. See Section 3.3.1. The ex-post payments should apply for the full period of non-compliance with the Regulation, not just *"from 1 January 2020 until 31 December 2020."*

4.2 PROPOSED DECISION SEM-21-027

4.2.1 Treatment in Scheduling and Dispatch

- *"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."*

ISEA agrees with this position.

- *"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."*

ISEA disagrees with this position. This is contrary to the legal requirements of non-discrimination under the Regulation (see Section 3.2). Variable controllable renewable generators should not be required to interact with systems designed for predictable dispatchable generators, and can easily lead to scenarios arising from procedural complications where available renewable energy is not delivered despite the technical capability of the grid to accept that power and the best efforts of the generator to trade that power.

- *"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."*

ISEA welcomes policy certainty as soon as possible (no later than Q1 2022), ideally not to adversely impact regulatory certainty heading into the RESS-2 auctions. This is where the focus should lie for the interim period.

We have recommended a phased approach to delivering compliance with the Regulation in Section 3.3. Note this ISEA is not in favour of rushed interim solutions until robust systems are in place. Rushing to implement one element of the Regulation (loss of Priority Dispatch) should not be done where it breaches other parts of the Regulation (principles of fair treatment of generators with different characteristics, unnecessary downwards redispatch of generation, etc.).

- *"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."*

ISEA agrees with this position.

4.2.2 Treatment in the Balancing Market

- *"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."*

ISEA agrees with the position.

- *"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."*

Please refer to our response in Section 3.3.3 which argues for portfolio-based ex-ante trading (facilitating aggregation in line with the ISEM High Level Design and the Regulation's requirements).

4.2.3 Bids and Offers

- *"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."*

ISEA agrees with this position, subject to comments on Bidding Principles.

- *"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."*

ISEA does not disagree with the approach, but believes it should be reviewed against the treatment of limited resources where there is no price differentiation across all timeframes for systems and markets (ex-ante markets, ex-post markets and scheduling dispatch) to ensure there are no unintended inefficiencies that arise.

- *"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."*

ISEA welcomes a review of the Bidding Principles, and believes it should be completed in line with the final decision on this paper (no later than Q1 2022). Please note our arguments as to why the application of the Bidding Principles results in discriminatory outcomes for subsidised renewables relative to the treatment of participants within the Capacity Remuneration Mechanism subsidy.

4.2.4 Treatment of redispatch (constraints)

- *"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."*

ISEA supports this position. See Section 2.3. It also, when implemented, resolves what we understand to be potential material issues regarding the operation of the EMS Dispatch Tool. See Section 3.3.2 for further descriptions of this issue.

4.2.5 Treatment of redispatch (curtailment)

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

ISEA supports this position. See Section 2.4.

- *"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."*

ISEA supports such a review, and notes not only the definitions in SEM-13-011 need to change, but also the mechanism to resolve constraints on a transitional basis (see Section 3.3.2 until a more enduring market solution is delivered (see Section 3.3.3)

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

ISEA believes this is an implementation issue, but agrees in principle that constraint and curtailment need to be differentiated within dispatch. Compensation for both – whether it is market based (under T&SC settlement, or for a transitional period within a Non-Market Settlement System) or non-market based (proposed to endure under a Non-Market Settlement System) – should be the same. See Section 2 in general around the classification and compensation of redispatch actions, and Section 3 for technical implementation considerations.

4.2.6 Arrangements for Implementation

- *"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."

Following the TSO Workshop on the July 1st, ISEA was concerned regarding the level of work required to implement the Regulatory requirements in market systems. ISEA acknowledges that both the SEMC position (and alternative proposals from others in industry relating to the classification of constraints, and subsequent treatment in dispatch) are challenging.

To that end, ISEA strongly recommends:

- A focus on policy matters (with technical feasibility reviews) to be delivered by Q1 2022; and
- On a transitionary basis only, leaving the existing central dispatch and settlement systems unchanged (with the exception of a Non-Market Settlement System to manage retrospective and ongoing compensation in the interim) until a more robust solution can be delivered for 2023/24. The arguments for this are given in Section 3.