CONSULTATION ON DISPATCH, REDISPATCH AND COMPENSATION PURSUANT TO REGULATION (EU) 2019/943 AND PROPOSED DECISION ON TREATMENT OF NEW RENEWABLE UNITS IN THE SEM

SSE Response

For a better world of energy

INTRODUCTION

SSE welcomes the opportunity to respond to the Consultation Paper SEM-21-026 Dispatch, Redispatch and Compensation Pursuant to Regulation (EU) 2019/943 and SEM-21-027 Proposed Decision on Treatment of New Renewable Units in the SEM. For the avoidance of doubt, this is a non-confidential response.

WHO WE ARE

At SSE we're proud to make a difference. From small beginnings we've grown to become one of Ireland's largest energy providers, supplying green electricity and natural gas to over 700,000 homes and businesses on the island. We are driven by our purpose: to provide energy needed today while building a better world of energy for tomorrow.

Since entering the Irish energy market in 2008 we have invested significantly to grow our business here, with a total economic contribution of €3.8bn to Ireland's economy over the past five years. We own and operate 890MW of onshore wind capacity across the island (including Northern Ireland's largest, Slieve Kirk Wind Park), offsetting over 700,000 tonnes in carbon emissions annually. Our portfolio includes Ireland's largest onshore wind farm, the 174MW Galway Wind Park, which was jointly developed with Coillte. We also own and operate the Great Island Power Station, Ireland's newest gas station and a strategic asset for Ireland's security of electricity supply.

As a leading developer of offshore wind energy in Great Britain, we believe offshore wind has the potential to transform Ireland's response to climate change. SSE is currently progressing the development of a consented offshore windfarm off the coast of Co. Wicklow - Arklow Bank Wind Park Phase 2. We also have plans to progress projects at Braymore Point and in the Celtic Sea.

SSE are proud to be a Principal Partner for COP26 – the 26th United Nations Climate Change Conference of the Parties – where world leaders will be seeking a more ambitious climate change agreement. We look forward to continuing to work with the UK government and other stakeholders to support the delivery of a successful and impactful COP in Glasgow next November.

EXECUTIVE SUMMARY

We have provided a general response that addresses the content of both the SEMC proposed decision and consultation regarding Clean Energy Package implementation. In summary we:

- Advocate that design and system change is inevitable when considering the full requirements of Article 12 and 13 in the currently configured SEM. The focus should be in creating suitably foresighted changes that will provide certainty for future entry to the market, whilst preparing the SEM for recoupling and interconnection with a new trade partner in 2025. We consider a design change of some kind is inevitable when we consider the full implications of the EU requirements and the unacceptable effects of the current proposals.
- Note the lack of justification that the proposals represent optimal or achievable solutions to implement the various aspects of Article 12 and 13. This is clear when we reflect on the system

limitations indicated at the TSO events on the 1st July. We provide some thoughts following that event.

- We support the WEI view that the current proposed implementation of Article 12 and 13 creates some unacceptable outcomes and gaps, i.e. removing of pro-rata constraints, creating uncertainty for RESS 1 and RESS 2 projects and providing no clarity regarding bidding principles and firm access.
- We agree that there likely is a strong legal argument for compensation of both constraints and curtailment.
- We also acknowledge that the design of the Regulations creates a downside-upside situation by virtue of a temporal threshold for eligibility to priority dispatch which cannot be realistically avoided, (though it should be minimised where possible).
- We have highlighted specific paragraphs in the Regulations and other interactions that have not been considered but which impact market and system design, and industry certainty on the direction that is likely to be taken. We would encourage engagement and consultation of how these broader requirements of Article 13 intend to be addressed and how they impact the proposals in the consultation.
- We are focussed on the overall aim of greater participation of wind in the market and what implications this should have in terms of system and market design.
- Appendix 1 outlines the various permutations of units and their treatment under the proposals. This table we feel illustrates how we tried to conceptualise the proposed changes.

We would like to indicate at the outset that presently there has been a sustained and significant volume of important consultations running alongside each other. We appreciate that some of the challenges at present may be due to the pandemic and necessary re-prioritisation of work. However, the same regulatory teams within the market participants' companies are handling all the consultations currently active. We would like to take this opportunity to request that the RAs seek better ways to coordinate between each other and separate internal teams to ensure that 1) the current glut of competing consultation deadlines is addressed; 2) there is sufficiently detailed signalling and treatment of interacting workstreams across all consultations; and 3) there are clear roadmaps of deliverables and milestones in place for workstreams. Lack of clear detail on interacting workstreams does not provide comfort to industry that these areas will be reviewed later. Instead, lack of clarity has the effect of placing further burden on industry in trying to work through whatever gaps, interacting workstreams or unintended consequences may impact the proposals.

We have heard that there is an intention for a workplan to be published of all future consultations. We would sincerely request that this be published as soon as possible. This will allow industry to plan better in terms of analysis and preparing for responses.

COMMENTS FOLLOWING STAKEHOLDER EVENT

We would have appreciated this workshop earlier in the timeframe of the consultation, rather than during the final week of the consultation deadline. It has thrown up additional complexities and uncertainties that make it almost impossible to arrive at a definitive conclusion at this time. We reflect on these in the section below.

Our reading of the TSO presentation is that the current systems and the new EMS Dispatch Tool both cannot handle the "grandfathering of constraints" as well as the implementation of non-market based constraints, in order to protect current pro-rata constraints. We appreciate there may be room for debate on this, but in our view this encourages several questions about how pro-rata will be treated in either scenario, i.e. where grandfathering cannot be applied but non-market based constraints can; or where neither can be delivered so by default pro-rata will continue to apply. One system limitation identified is the capability of the price optimiser, which we recall has been raised when the feasibility of some TSC modifications has been assessed. We would have assumed that the better of any two values would be a useful starting point, on the basis that dispatch down is treated the same.

The inherent difficulty with implementation of Article 12 and 13 in our opinion, lies with the central dispatch system, unit-based approach, and a chronic degree of constraints in our market, which has not been sufficiently addressed through infrastructure development. We agree with the suggestion from the TSO that central dispatch is a potential barrier to implementation of non-priority wind. The continued retention of central dispatch must be seriously considered given its impact on EBGL, Article 12 and Article 13 implementation. We also welcome the prioritisation of loose volume coupling but would ask that this is considered in the context of wider compliance again with EU requirements.

The TSO clearly indicates that Article 12 and 13 represents significant, time-consuming, and complex change. The impact of code release lead times (18 months) for inclusion in the scope of future code releases, cannot be underestimated. Whilst this delivery timeframe is realistic, it means that decisions need to be made sometime in 2021 to ensure that these can be included in the scope of code releases scheduled for deployment in 2023. We are not clear that the workstream is at the stage of finalising specific decisions in time for deployment in 2023. A roadmap with clear milestones and deliverables would be welcomed to demonstrate what is intended to be delivered by 2023 and through meeting what interim milestones.

We have seen since the start of the new market that the system provider-TSO arrangement holds virtually no accountability regarding delivery. We acknowledge that this may have improved slightly with predictability in releases and a prioritisation of certain delivery, but it still holds true that the TSO is not sufficiently empowered to be able to prioritise and fast-track projects outside the system delivery limitations set out by the vendor. This issue suggests an additional focus in the price control regarding procurement protocols (on which we will elaborate in that separate consultation). It also points to a more fundamental question about why we are not considering whether new systems, or new design (self-dispatch/adjustment to priority dispatch treatment), should be a factor in delivery. If existing systems cannot fully implement the Regulations in the most optimal manner, then new systems should be seriously considered. In our opinion, the foundations created by the Electricity Regulation, EBGL[1] and LVC[2] requirements clearly signal the need for a market by 2025 that will be an equal and credible participant in Europe, attractive for and capable of cross-border coordination, and capable of managing new interconnection with Europe via Celtic. With this in mind, we consider that clear and decisive implementation can be delivered now. If we wait until later, we believe it likely to be more challenging, expensive, or complex.

Finally, a system delivery of 2023 or later gives no certainty for RESS projects including RESS 2. This will cause significant concern in the market and for the process of securing financing for these future projects.

---

[1] Electricity Balancing Guidelines
[2] Loose Volume Coupling

It is critical that comfort for RESS 1 & 2 projects is given separately, during the course of implementation of Article 12 and 13. This will allow projects to continue ahead without waiting until after the auction for clarity on their treatment. Separately, defining of constraints as non-market based as a method to provide certainty for RESS (but without compensation), is not necessarily complaint with Article 13. We would also not consider that lack of competition in constraints could be resolved by re-establishing pro-rata of constraints. Without specific incentives towards reduction of constraints and other measures to mitigate lack of competition, constraints simply remain an unchanging fact of operation, that pro-rata treatment improves but does not remove.

Considering these factors, we are concerned with the options open to the RAs when it now appears clear that both "grandfathering" of constraints, as well as classification of constraints as "non-market based" for the purposes of preserving pro-rata treatment, are not possible in the current systems. Following the TSO stakeholder event, the substance of proposals appears to have changed due to the system limitations highlighted. Therefore, the status of these papers and deliverables of this project need to be carefully reviewed.

ARTICLE 12—PROPOSED DECISION ON THE TREATMENT OF NEW RENEWABLE UNITS

We understand that the approach for category 2 units is to require these participants (primarily wind and solar that would previously have been priority dispatch), to actively bid into the market and submit technical and commercial offer data to the TSO. We also note consideration of additional information, for instance around engineering tolerances, to be provided. In principle, it is our view that this should be possible and would not pose any additional burden. However, we would like further clarity on what is exactly expected.

An initial comment to the proposals is that there are Category 1 and 2 classifications in dispatch at the moment relating to controllability.[3] Where a wind farm does not comply with set point instructions, they are classified as Category 1 and are curtailed first (as a penalty for failure to comply). We assume that Category 1 and 2 in the Article 12 paper are not related to these existing categories in dispatch and scheduling. However, confirmation would be appreciated.

It is our preferred position that the Wind Dispatch Tool is the best option for delivery of the proposals outlined in this paper. We were encouraged to see, judging from the TSO stakeholder event on the 1st July, that the Wind Dispatch Tool (now called EMS DT) appears to be the best solution possible given limitations identified with EDIL.

OPT-OUT OF PRIORITY DISPATCH

The Electricity Regulation envisages that relevant authorities may wish to encourage the opt-out of priority dispatch by units. It is our assumption from the treatment of priority dispatch under the separate Article 13 that the objective is to set priority dispatch compensation lower in an effort to make priority dispatch less

[3] Wind Farm Controllability Categorisation Policy (March 2012).pdf

attractive and encourage re-registration of units as non-priority dispatch. However, where this may be the aspiration, we agree with WEI that there are various factors missing to encourage this action.

In our opinion, Article 12 is clear, *"Member States may provide incentives to installations eligible for priority dispatch to voluntarily give up priority dispatch".* Thus incentivises (which we consider should be positive), should be applied to encourage voluntary opt-out, rather than disproportionate application of compensation, which has not been accompanied with any justification that would align with the caveats under Article 13(7). To provide clear incentives, the two policies that require amendment or development are bidding principles and firm access policy. This would provide certainty regarding favourable eligibility of compensation for redispatch as well as the possibility to mitigate exposure to redispatch through the bidding principles framework.

In the absence of clarity on bidding principles specifically, we would question the appropriateness of indicating that the Article 12 paper is a proposed decision. The two SEMC papers allude to market changes and proposed compensation arrangements for treatment of eligible redispatch but fail to consider other matters of concern to market participants. Namely, how units will be allowed to and be able to bid in their costs, participate in the market, and mitigate the exposure of redispatch. Without this critical detail, it is very unclear and uncertain as to overall unit revenues and the market landscape following these changes. This has made it exceedingly difficult for parties to understand the full value of changes where units are classified as non-priority dispatch.

BIDDING PRINCIPLES

It would be our preference that BCOP[4] is amended to allow non-priority dispatch plant to bid into the market. BCOP is currently operational and known in the market. It would also provide sufficient flexibility as a transition into the market for wind being redesignated as non-priority dispatch. In contrast, the BMPCoP[5] is currently not in place and was developed in a scenario that did not anticipate dispatchable wind. SSE would consider it disproportionate to consider applying BMPCoP only to dispatchable wind when BMPCoP currently cannot be applied to the rest of the market as a whole. In the absence of any detail as to how the market will transition to the BMPCoP, it is our view that dispatchable wind can only be treated like other generators through the BCOP. Until BMPCoP is appropriately amended and reintroduced for all generators, BCOP is the only suitable option.

We understand that bidding principles is handled by a different team to the one leading the overall implementation of the Clean Energy Package. However, we would have expected a coordinated approach where detail could have been provided to give a full picture of the market and revenue landscape following implementation of Article 12 and 13. We would ask that this is progressed as swiftly as possible, and that consultation responses from participants that relate to the bidding principles, are shared with the relevant subject matter experts within the RAs. To this end, we have provided views below of the considerations that this team should review:

[4] Bidding Code of Practice
[5] Bidding Market Principles Code of Practice

1. **Opportunity costs:** these should allow for the cost of any avoided support payments to be recovered when an eligible wind unit is re-dispatched. We note that REFIT and ROCs are considered ineligible under Article 13. We consider there is no justification provided by the RAs or in the Regulations to support this approach. Allowance for opportunity cost we also do not believe disadvantages our thermal units in the market. Such an allowance in the bidding principles addresses several elements:
   a. the legitimate revenue loss of redispatch which a unit should be legitimately allowed to reflect,
   b. the need to incentivise opt-out of priority dispatch by fully reflecting the benefits of non-priority dispatch in the market; and
   c. the need to reflect the practical costs for wind in the market where their costs do not relate to fuel but do relate to support schemes in certain circumstances.
   d. Requirement for active reduction of redispatch through clear market signals —this is discussed further, below
2. **Commercial offer data restrictions:** confirmation that restrictions on the submission of commercial offer data for controllable wind that is deemed non-priority dispatch will be relaxed.
3. **Transition to BMPCoP:** Where there is an intention to transition to BMPCoP from the current BCOP, this intention is signalled and there is a clear path of transition applied to the whole market, to ensure that parties are aware of the likely market landscape in future.

REDUCTION OF REDISPATCH

Where bidding principles create a positive signal to motivate reduction of redispatch, this incorporates the following aspects of Article 13:

- Article 13(5)(a) regarding avoidance and minimising of redispatch at no more than 5% and general requirements under Article 13(5) that relate to the efficiency and flexibility of the network to continue to accommodate more renewables without a resort to downward redispatch.
- Article 13(6)(a) that downward redispatch is used only as a last resort unless there is a system security need or no other alternative
- Article 13(6)(d) with reference to justification for downward dispatch
- Article 13(4) reporting of measures taken to reduce the need for downward redispatch

Active reduction of redispatch is clearly part of the implementation of Article 13 and has not been clearly considered as it relates to bidding principles (Article 12), and furthermore in relation to Article 13 compensation. We acknowledge that reduction of constraints has separately been referenced in terms of price control expectations, though with no indication of the intended incentive framework. We would actively encourage the reduction of constraints through price control mechanisms (including with clear downsides until such time as constraints are at or below 5% as specified under Article 13(5)). The link to infrastructure development as outlined in the TSO Electricity Futures papers must also be considered and actively addressed to meet the broader requirements of Article 13. Until such time as redispatch is at or below 5%, the need for compensation for redispatch will continue to be significant. Therefore, the push for units to have delayed delivery of firmness or continued application of non-firm access, will continue be an unfair necessity. Constraints and firmness have a direct impact as investment signals for entry and exit in the SEM. We discuss the link between firm access policy and Article 13 further in this response.

MARKET SIGNALS

As mentioned, recovery of the opportunity cost of support schemes lost through redispatch, in bidding principles will create positive market signals. Specifically, this option for recovery would flow through imperfections and motivate the reduction of constraints and building of infrastructure. This would mirror the approach in GB in terms of creation of market signals for network development.

Where up to now, incentives have failed to address this issue, solutions in the market are a significant tool to help reduce constraints. Positively impacting the reduction of constraints through market signals would:

- align with price control aspirations towards incentivising constraint reduction,
- wider expectations under Article 13 such as measures to mitigate downward redispatch reported on an annual basis,
- signals in the CRM regarding constraints and capacity contract terms, i.e. in relation to the considered temporary nature of constraints and associated shorter contract terms,
- the need for clear investment signals for entry through positive support of constraints reduction,
- have a positive impact on the size of the PSO levy (depending on how it is implemented),
- align with national and European renewables targets that necessitate high volumes of penetration, and
- over time intuitively have a positive impact on the degree of compensation (under Article 13), that is due to market participants.

ARTICLE 13—DISPATCH, REDISPATCH AND COMPENSATION

We have provided comments below in line with the headings specified in the executive summary of SEM-21-026. Briefly, our view is that further work is needed to develop these proposals, specifically where there are interactions with connection policy, bidding principles and system delivery limitations.

DISPATCH AND REDISPATCH

We have considered the interpretation in this area regarding energy balancing being defined as dispatch, versus redispatch. In this regard, we are of the opinion that a significant degree of work is needed to consider how this interpretation, which broadly aligns with non-energy actions, can be implemented in the market. We would not necessarily accept the view that since these are ex-post scheduling decisions, therefore there is no need for further consideration of whether this best meets the requirements under the Clean Energy Package. As above, we point to the variety of workstreams that overall have an impact on the type of market will be in place between recoupling with Europe, and a new trade partner.

DECREMENTAL ACTIONS ON PRIORITY DISPATCH UNITS

We appreciate that the most suitable approach is ambiguous as to whether the dispatch of priority dispatch units constitutes as only non-energy or a combination of energy and non-energy actions. This binary interpretation is very much based on assuming an “absolute” priority continues to be afforded to these units. Upon review of the issues surrounding “grandfathering” of constraints and the loss of pro-rata constraints, our view is that the absolute protection of priority dispatch units is causing the associated issues with implementation of Article 13 in the SEM. We would encourage consideration of the overall impact of priority dispatch in the market.

The SEM was designed with priority dispatch "baked into" how scheduling and dispatch, and constraints and curtailment are understood and actioned, rather than allowing the market to create some/all of the necessary signals. By contrast, in GB, priority dispatch is only used as a tie-break solution, rather than as an absolute protection. This would resolve the issue of loss of pro-rata since constraints can again be applied across the full spread of wind generation. The current systems appear incapable of implementing the "grandfathering" of constraints that arise with preserving the absolute protection of priority dispatch and are neither capable of defining constraints as non-market based given the price optimiser configuration. Thus, the status of priority dispatch, especially where the removal of priority dispatch is clearly an objective under the Clean Energy Package, should then be considered.

The erosion of "absolute" priority dispatch would have the following positive outcomes:

- it would allow the TSO to take more economic decisions in redispatch which would represent a saving to consumers. Considering the context of greater push for cross-border participation, we would expect there is increased pressure to ensure that redispatch can be actioned on a more economic basis.
- It would also ensure a level playing field for future wind penetration, which is necessary to meet 2030 targets.

The general aspiration of the Clean Energy Package in removing priority dispatch and allowing for incentivising of generation to opt-out of this status, should be aligned. At present, the two-tier compensation proposals from the SEMC only appear to seek to motivate an opt-out of priority dispatch. As discussed, this approach alone is not sufficient to motivate this change in unit registration in the market to any great scale, especially if we consider the absolute protection of priority dispatch.

We realise that there are units that may wish to or should continue to retain priority dispatch as identified in the Electricity Regulation. We acknowledge some participants may also not have the resources to participate directly in the market. We do not wish for incentivising of opt-out or redefining of priority dispatch to reduce market access for these parties. However, as the end goal is to encourage active market participation of wind and a transition away from priority dispatch, (which is clear), then a focus on suitable market design, firmness policy and bidding principles fully, would provide clarity for wind generation.

MARKET AND NON-MARKET BASED REDISPATCH

Previously, we have been clear regarding the interpretation of constraints and curtailment as separate sides of redispatch, i.e. market and non-market based. We agree with WEI that the current interpretation, which separates these two actions, creates several serious issues especially future RESS 1 and RESS 2 projects in securing of finance for these projects.

It is our view that as above, there are other ways to address this by considering the application of priority dispatch in the SEM. But in principle, we can also see that there is nothing in Article 13 that would prevent constraints from being included as non-market-based actions deserving of compensation. We agree with

WEI that these are actions that wind units have no control over, especially since these units cannot submit PNs to help avoid these actions and cannot participate in the market.

There is a view that due to inherent benefits of priority dispatch, i.e. maximising the volume of renewable generation that can be facilitated and absolute protection from redispatch, compensation should be less forthcoming. The drive for increased wind penetration to meet 2030 targets outstrips the initial view of balancing newly entering wind dispatch against thermal generation. As significant volumes of thermal generation are also due to close, the approach should be to assume an obvious higher renewables fuel mix beyond simply seeking a transition of wind into the fuel mix, which was the previous goal of priority dispatch. It would appear the rationale for priority dispatch is no longer as relevant. Furthermore, priority dispatch does not resolve the loss of support revenues and compensation for redispatch, since it involves an action that these units have no direct control over. In other words, wind units cannot mitigate their exposure or risk of redispatch, and they cannot self-dispatch out of this situation either. Priority dispatch is insufficient protection to justify that these losses should not be fairly recovered. SSE's preference would be to allow for units to be able to actively reduce their exposure through submission of PNs regardless of status as priority dispatch and non-priority dispatch. This approach should still occur side by side with active constraint reduction by the TSO as expected under Article 13.

COMPENSATION UNDER ARTICLE 13(7)

We understand that the proposals under this section relate to the following:

- Compensation for curtailment (system only and not energy balancing), for both priority dispatch and non-priority dispatch but with different treatment. It is assumed that priority dispatch being treated to a lesser compensation is a method to address the provision under the Clean Energy Package for encouraging an opt-out of priority dispatch for those generators that otherwise have the right to retain it.
- Constraint remains market based and compensated through the market. Though we have heard that the "grandfathering of constraints" issue has led to consideration of the methods by which the current pro-rata approach could be preserved.
- We assume that compensation will be backdated to 1 January 2020 when this mechanism was required to be in place.

FIRM ACCESS POLICY

Compensation under Article 13(7) centres around provision of compensation where redispatch is provided, but on the basis that producers have secured "guarantee of firm energy delivery". This does not appear to be in line with the current interpretation and application of "firmness" in the SEM, which the TSO also alluded to at the 1st July event. We would ask that there is clarity provided on this interpretation in the first case.

To date, there has been a historic under delivery of necessary network reinforcement in line with the expectations provided as a condition of connection offer acceptance. Whilst we acknowledge the consistent response is that these are forecasts and non-binding, they do represent the only confirmation that generation has when planning the financeability and future revenues of a unit. The full provisions under

Article 13 are clear that compensation **shall** be provided where redispatch is resorted to and indicates that the current approach of consistently postponed delivery of firmness must change. Delays in a "guarantee of firm energy delivery" is outside the control of generators and there must be a prioritisation of delivery and amendments to ensure that whilst firmness is delayed, due compensation under Article 13 is not neglected.

We support the WEI response that consultation on this matter is needed urgently. We would go a step further to point out that this should have been consulted on as a requirement under Connection Policy at some stage in 2021. Firmness policy is a vital detail for the implementation of Article 13, without which, the wind industry has no clarity regarding compensation. Firm Access is a complicated area that requires immediate industry engagement by the System Operators with a focused consultation on the specifics of this.

We agree with WEI that the starting point for firm access policy and how it is understood in the context of Article 13, is that firm access allocates the risk of delays to the parties (i.e. SOs, RAs and government policy) best placed to manage this risk. However, in the meantime while firm access is being delivered through ATR undertakings, units are at a disadvantage as compensation due to them under Article 13(7) remains uncompensated. The way through this is to provide some "interim" firmness, that will secure compensation while "technical firmness" is delivered, and alongside reduction in constraints which can hopefully speed up delivery.

It is essential that a consultation on firm access policy considers application for (i) existing firm projects, (ii) existing non-firm projects that had firm access date advised, (iii) existing non-firm projects and (iv) future projects, and how firm access is confirmed/communicated for each of these types of projects to be considered. A new policy should also give consideration of other solutions/measures which can help mitigate any delays in ATR completion (i.e. Smart grid solutions including DLR, virtual battery network, power flow control devices, new and emerging long duration storage technologies, and hydrogen).

It would also be our preference that "interim" firmness be applied to existing units that still have expectations of firmness up to a specific date (such as the effective date of compensation being 1st January 2020 as specified in the Electricity Regulation). This should be an amendment applied to existing connection agreements and a new article within new connection offers. Beyond 2020, delivery of firmness must focus on a clear and transparent guarantee with or without application of "interim" firmness for the purposes of redispatch compensation, perhaps after some initial period following energisation. All of this we consider must form part of a significant consultation on this matter.

Certainty around firm access will ensure that RESS auctions can deliver more successful and efficient outcomes for investors and consumers in allowing unit bids to exclude/reduce contingency for this risk in their bid prices. It will also honour the expectations and requirements of the Regulation and provide a strong incentive towards the reduction of compensation by the delivery of infrastructure development. Clarity on firm access will also generate positive signals for investment which will help improve the market's self-sufficiency in generation, for security of supply.

SUMMARY

We acknowledge that the requirements under the Clean Energy Package pose a significant and complex challenge, at a time when we are still stabilising the new SEM. We have sought to respond to the proposals in a pragmatic manner acknowledging that the fundamental requirements of the Regulations do create an upside and downside by virtue of temporal thresholds. We support several of the views raised on behalf of industry, by WEI. We appreciate the efforts to progress the interpretation and development of proposals to implement Article 12 and 13 for the market. It would be our preference that these requirements are approached in a holistic manner, taking greater account of interacting factors, the spirit and objectives of the Regulations and the best measures possible to meet the requirements.

APPENDIX 1

The table below illustrates how we have sought to conceptualise the proposals across other interacting areas.

Status	**Proposal under Art 12 priority dispatch**	**Compensation for constraint and curtailment**	
		Now	**Future –proposal under Art 13 compensation**
Non-firm generator with PD (assume supported—REFIT, ROCs)	Remain PD and non-dispatchable but controllable (i.e. no ability to trade in the market or submit unit data)	Would have exposure to PIMB, but no CDiscount payment. PSO levy interaction with REFIT means these units will lose some of the compensation	Get no compensation since based on firmness. Many non-firm generation that is renewable has been awaiting firmness for many years prior to 2021. We agree with the WEI that firmness policy for these units is a necessary element of the implementation of Article 13. Assumed to be re-dispatched ahead of a firm PD unit.
Firm generator with PD (assume supported—REFIT, ROCs)	Remain PD and non-dispatchable but controllable (i.e. no ability to trade in the market or submit unit data).	Get better of CDiscount and CPremium or CIMB (effectively retain Day Ahead Price) PSO levy interaction with REFIT means these units lose out on some compensation.	Compensation for curtailment at the cost of additional operating during dispatch down only. Since these units are firm, the incentives should be increased to encourage opt-out of priority dispatch for these parties. Our recommendation is for bidding principles to be amended to allow for loss of support payments to be able to be recovered where re-dispatched/dispatched down.
Non-firm generator with non-PD (assume RESS)	Dispatchable generation, bidding into the market. In dispatch schedule will be dispatched down first ahead of PD (this view does not take account of where thermal is in the merit order). However, is this a move from pro-	Would have exposure to PIMB, but no CDiscount payment. Given that it is assumed the PSO arrangement will apply for RESS—it is assumed same treatment.	No compensation since it is based on firmness. It is clear under Article 13 that compensation is due where redispatch is actioned. Whether this includes constraints or only curtailment, a lack of firm access is preventing these parties from receiving compensation that they are due.

	rata constraints and affects constraints assumptions for RESS 1. This is termed "grandfathering of constraints" by WEI		Terminology under the Regulation is "guarantee of firm delivery of energy". Is this analogous with "firmness" as understood in SEM? ATRs even if continually pushed out, represent a guarantee for the wind unit of firm energy delivery, which is included in financial projections and assumptions regarding viability of a site. Therefore, this should be considered. Agree with the WEI that a firm access policy must be produced and consulted as a matter of urgency. Same approach under PSO for RESS. Also, possibly additional compensation for curtailment as specified under the RESS1 Terms and Conditions. We cannot at this stage quantify what this additional compensation may look like, or if delivery of compensation under Article 13 satisfies this requirement fully. Assume, but require clarity that these units would be dispatched ahead of firm non-PD. It is clear from proposals that these units would be downward re-dispatched ahead of PD units due to absolute protection of PD in SEM high level design.
Firm generator with non-PD (assume REFIT or ROCs)	Dispatchable generation, bidding into the market. In dispatch schedule will be dispatched down first ahead of PD. (this view does not take account of where	Does not currently exist in practice. Get better of CDiscount and CPremium or CIMB (effectively retain Day Ahead Price)	Compensation of curtailment at the DAM price. This is usually higher than zero. The proportion of these in the market are likely to be very low at present, unless they are previous firm priority dispatch units.

	thermal is in the merit order)	PSO levy interaction with REFIT means they lose out on some compensation.	We advocate amendment to bidding principles and firm access policy for these units which need to participate in the market directly. It is assumed that these units would be downward re-dispatched ahead of PD units due to absolute protection of PD in SEM high level design, despite being firm. This appears inappropriate given the value of firm access.