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Subject: Implementation of Articles 12 and 13 of Regulation 2019/943 in relation to Dispatch and Redispatch, consultation SEM-20-028 (the Consultation)

Dear Gina and Gary,

A. Introduction and Context

Bord Gáis Energy (**BGE**) welcomes the opportunity to respond to this Consultation on the implementation of Articles 12 and 13 of the Clean Energy Package's Electricity Regulation (**the Regulation**). The Consultation is potentially far-reaching in its scope but at a high level BGE believes that the crux of the implementation decisions required comes down to two things: i) how will renewables (**RES**) that do not have priority dispatch[1] be treated in the market on as level a playing field as possible with non-renewables (**non-RES**), and; ii) how should RES, with and without priority dispatch, be compensated for constraints and curtailment in SEM.

BGE believes that it is pertinent to this Consultation that legislation, and certainly Articles within legislation, should be read in context. A purposive approach to interpreting and applying EU legislation locally, be that legislation that is directly applicable or of direct effect, is necessary. The "purposive" approach is a well understood term in EU law and effectively requires a "holistic" application whereby the general direction of EU energy policy, the intent of the legislation and the local market operation and investment situation are all relevant. While the aims of the EU energy policy and the Clean Energy Package (**CEP**) are many, its overarching goal from an electricity perspective can be described as decarbonisation. The Regulation's recitals which are instrumental in understanding the intent of legislation reflect this in saying "*decarbonisation of the electricity sector, with energy from renewable sources becoming a major part of the market, is one of the goals of the Energy Union... [T]o support this shift to variable and distributed generation, and to ensure that energy market principles are the basis for the Union's electricity markets of the future, a renewed focus on short-term markets and scarcity pricing is essential*."[2] This context is in our view essential in determining how to correctly apply the Regulation, and specifically Articles 12 and 13, locally. One intent behind the Clean Energy Package as reflected in this recital is to create a more level playing field amongst all participants including RES by *inter alia* requiring units to have balancing responsibility and be flexible. By corollary, to the extent that RES is supported by financial incentives such as a subsidy, such incentives should be transparent and not interfere with the efficient operation of a competitive wholesale electricity market. Equally, units that have benefitted from subsidies but now operate on a "merchant" basis should be better integrated into the market and operate on a level playing field with non-RES. Additional payments to them for their market interaction is thus not considered warranted.

Recital (25) is also particularly pertinent in our view where it states that "*…<u>derogations from fundamental market principles such as balancing responsibility, market-based dispatch, or redispatch reduce flexibility signals and act as barriers</u> to the development of solutions such as energy storage, demand response or aggregation. … broad derogations covering entire technologies are not consistent with the aim of achieving efficient market-based decarbonisation processes and should thus be replaced by more targeted measures."* This in our view evidences the intent that this Regulation seeks to ensure that the outcome of its application/ implementation locally minimises the extent to which favourable treatment is afforded to some units (whether new or existing) over others in balancing, constraints or curtailment. A level playing field is being pursued.

[1] Be that due to the fact that they do not "qualify" for priority dispatch status or have decided to drop priority dispatch status
[2] Recital 23 EU Regulation

Finally, in terms of pertinent recitals from the Regulation, we note that as early as Recital (2) it is noted that "*[T]he Energy Union aims to provide final customers – household and business – with safe, secure, sustainable, competitive and affordable energy*". The achievement therefore of the various objectives pursued by the CEP and this Regulation should not be pursued at all costs - strong cognisance to the cost of the transition to final customers/ the end consumer must be borne in mind.

In BGE's view it is clear that the CEP is looking to better facilitate decarbonisation by balancing the objective of increasing renewables to meet EU targets with the need for ensuring an efficient, competitive market by levelling the playing field as far as possible among all market participants. Simultaneously, electricity is to be available at an affordable price. Consequently therefore, it is not obvious that the Regulation intends to improve the financial situation of investments that are already made. Rather, the Regulation appears to seek to rectify deviations that undermine fundamental market principles such as the concept of priority dispatch. Removing advantages within the market such as priority dispatch should help achieve the stated aim of market-based investments in the sector while decarbonising the energy system.[3]

While the wording of a Regulation's provisions is often interpreted in a number of ways, a non-contextual interpretative approach may be unreliable. A more reliable approach may be to consider Articles 12 and 13's provisions holistically, by which we mean considering Articles 12 and 13: (a) in context of each other; (b) in context of the intent of the CEP and Regulation's intention as a whole; and (c) in context of the practicality of making general principles relevant and appropriate to specific local EU markets that are different from each other. A reliable application of the legislation would require that decisions made, particularly with regard to compensation for constraints and curtailment, should not improve the financial situation of existing investors as they have already invested on the basis of the existing investment landscape and are already contributing to the decarbonisation agenda. A reliable application should instead seek to apply the Regulation's provisions in a manner that best balances the transition of RES with no priority dispatch into full market interaction on as level as playing field as possible, against minimisation of the cost of this transition to consumers.

BGE agrees that the RAs, in determining the appropriate application of Articles 12 and 13 locally, should consider their duties to minimise and duly justify costs to the consumer.[4] Indeed affordability of energy is one of the objectives of the Energy Union.[5] We also contend that:

- maximisation of day-ahead-market liquidity;
- incentivisation of balance responsibility and flexibility;
- balancing RES investment signals with placing RES with and without priority dispatch on a more level playing field with non-RES market participants;
- ensuring the TSO has the necessary signals to invest in much needed network improvements and/ or DS3 services; and
- minimisation of early TSO non-energy actions,

are relevant factors to consider in applying the provisions of Articles 12 and 13.

We believe that our views put forward below on how the Regulation can be applied in the SEM capture these priorities and reflect the reliable approach we proffer above.

In terms of the questions raised in the Consultation, with respect to Article 12 and the proposals around how to integrate non-priority-dispatch RES into the SEM, given the extent of RES development expected over the next decade and beyond in SEM, we urge the RAs to ensure the TSOs are in a position to implement the necessary system changes that will materialise as soon as possible. In general, BGE's views are largely aligned with the RAs' perspective on how to create a more level playing field within the operations of the wholesale market between non-RES and those non-priority-dispatch units. Ultimately BGE seeks to have all dispatchable and non-dispatchable RES units to be able to interact in the market in the same way as non-RES units with no priority dispatch do. This includes the submission of commercial and technical offer data, physical notifications as well as incs and decs in accordance with bidding rules. The biggest areas we might deviate from the RAs' proposals are around interim or alternative solutions given that we believe that system changes need to occur as soon as

[3] DG ENER https://ec.europa.eu/energy/sites/ener/files/documents/electricity_market_factsheet.pdf
[4] Be that imperfections charges for dispatch balancing costs or the PSO charge
[5] Recital (2) of the Regulation, "The Energy Union aims to provide final customers – household and business – with safe, secure, sustainable, competitive and affordable energy…"

possible. We also suggest some solutions that place non-priority-dispatch RES on a more level playing field with priority dispatch RES, in line with the spirit of the CEP and the Regulation.[6]

With respect to Article 13, we address the issue of compensation as a matter of priority. Ultimately, we believe that the Regulation (while it requires that constraint 'compensation' should be made) does not necessarily imply any need to change the current approach to constraints payment be that in the market or via REFIT. It could credibly be argued that deviating from the status quo could run contrary to the legislation's intent given that the aim is to move away from market distortions such as priority dispatch with a view to creating a more level playing field with non-RES and RES with no priority dispatch. Further enhancing the revenue for existing units, both in receipt of REFIT or operating on a merchant (out-of-support)[7] basis, is not in our view conducive to levelling the playing field or achieving affordable energy for end consumers. BGE makes the argument below that existing units in receipt of REFIT are already adequately "compensated" for constraints.[8] Furthermore, existing RES units not in receipt of REFIT would under existing market systems receive constraints payments in an equivalent manner to non-RES units[9] which is highly conducive in our view to levelling the playing field amongst all market participants. Thus, a change to current arrangements for constraint payments is not necessarily required at this point in our view.

With regard to curtailment, given curtailment is driven by the existence of priority dispatch units who, due to how the system is operated, are the only units that might be seen to benefit from any move from 'zero' curtailment compensation, there is a credible case for retention of zero compensation given that these units are arguably already compensated by their REFIT price for curtailment also. Paying them additional revenue would bolster their current investment position treating them more favourably than their current priority dispatch status does now. Given that priority dispatch units are protected from balancing risk when in receipt of REFIT, compensation for curtailment would not go towards mitigating that risk and would result in extra costs to consumers. A valid question is whether the money could be better spent by the TSOs in developing the network and DS3 services to cater for the increasing new RES we need on the system to meet 2030 targets.

We address the questions in the Consultation in order of priority from BGE's perspective starting with Article 13. The order of question priority takes into account the potential magnitude of the impact of the decision as well as the complexity and likely need for further consultation that will be required on some issues.

B. RAs' interpretation of the scope of Article 12 & 13

Q1: Do you agree with the RAs' interpretation of the requirements under Articles 12 and 13 and specifically the application of dispatch, redispatch and market based/ non-market based redispatch in the SEM?

Yes, we agree with the RAs' interpretation of the requirements under Articles 12 and 13.

Articles 12 and 13 of the Regulation relate respectively to 'dispatch' and 'redispatch'. The former has been interpreted by the Regulatory Authorities as relating to (a) priority dispatch and (b) the integrated scheduling & dispatch process of balancing energy as explained in the TSO's Balancing Market Principles Statement. The latter – redispatch – is interpreted by the RAs as relating to (a) constraints and (b) curtailment, as we understand these two terms in the current SEM.

[6] Please see answers under section B below where we suggest that if curtailment arises it only applies to priority dispatch units due to the way the TSO operates the system and that non-priority-dispatch units should be constrained (and paid) before curtailment of priority dispatch (**PD**) units (who do not necessarily need to be paid)

[7] Considering that merchant units would have already benefitted from long term REFIT payments and the legislation in our view arguably does not seek to compensate them further for their investments. Instead progress towards full market integration akin to non-RES units is what the Regulation aims for

[8] Given that spot prices are greatly reducing with resulting increasing payment requirements on the PSO

[9] I.e. being kept "whole" to the higher of their bid price or the balancing market price

“Dispatch” is not defined in the Regulation but based on Article 2’s definitions of ‘priority dispatch’[10]; ‘redispatching’;[11] and ‘central dispatching model’[12] BGE believes that the RAs’ interpretation of *Article 12 (Dispatch)* and *Article 13 (Redispatch)* is an accurate view of the legislation.

The ‘redispatch’ provisions of the Regulation make an explicit, but important (critical from a compensation perspective) delineation between “market-based” and “non-market-based” redispatch. While neither of these terms are defined in the Regulation, a plain English interpretation would point to the view that “market based” infers some sort of price or economic order applies for choosing what units to redispatch at a point in time. Constraint decisions in SEM are all based on a price, be that a self-determined price by the market participant or an assigned price by the TSO for priority dispatch purposes. Notwithstanding that RES with priority dispatch is ‘assigned’ a decremental bid by the TSO, that bid is set against other prices within the market to ensure priority dispatch is maintained and it can therefore be considered a price influenced by, and determined on, a market place. BGE therefore agrees with the RAs’ interpretation that “constraints” equate to “market-based redispatch” in SEM. Curtailment on the other hand applies on a pro-rata basis. Due to its definition and the pro-rata rule, by its nature (and lack of price/ economic indicators influence in determining who it applies to), curtailment in SEM must necessarily fall under the “non-market-based redispatch” category as proposed by the RAs.

C. Article 13 – General View and Key Questions and Answers

As outlined to an extent in Section A above, BGE believes that a non-contextual reading of an Article within legislation can lead to inefficient outcomes which could ultimately be to the detriment of the consumer. Taking Article 13 for example, Article 13(2) on the face of it states that market-based redispatch (constraints in SEM) shall be “financially compensated”. However, Article 13(2) is silent on matters such as whether constraint compensation should be paid to firm and/ or non-firm units and to what extent local market settlement approaches can be taken into account in determining whether constraint compensation is already being made. As expanded upon previously, the driver behind these provisions and the Regulation overall is the facilitation of growing renewables in the decarbonisation transformation but in a manner that sees priority dispatch volumes reduce and sees more and more RES come onto a level playing field with non-RES. Taking all of these factors into account in our view allows the conclusion to be drawn that the current constraint compensation mechanisms in SEM are fit-for-purpose (and in some cases more than fit-for-purpose).

Take non-RES in the first instance for example. At a high-level, firm volumes constrained down from their ex ante traded volumes are “kept whole” to the higher of its bid or the balancing market price. This is a fair approach and mitigates the impact of a poor network on the flows of traded volumes. Taking then RES that has REFIT support for example and the constraint compensation that is applied there, in the first instance for firm volumes a similar “kept whole” approach as that for non-RES applies. These “kept whole” payments are then taken into account in total market revenues calculated as having been received by the unit when it comes to REFIT settlement and the PSO top-ups required which consumers bear in full. While REFIT top-ups are made only for metered output it is BGE’s view that the level of the PSO top-ups that units are receiving for their metered volumes could, in the context of eroding spot market prices and the related jump in PSO payments year on year, be deemed to be adequate “compensation” for the constrained volumes these units endure. As stated, Article 13(2) does not go into the specifics as to what might be deemed “compensated” – it is not necessarily a straight payment X constrained volumes solution - a reliable, holistic view of local market operation and settlement as well as consumer costs can rightly be taken into account in this determination of what constitutes constraint ‘compensation’. To apply an alternative approach to RES supported by REFIT would arguably go beyond the intent of the Regulation (which does not seek to bolster existing investment cases). As firm RES units have already invested, a change in constraint compensation approach could be viewed as a “windfall” to such units the cost of which would ultimately be borne by consumers through the PSO. Moreover, retention of the status

[10] Priority Dispatch: “means, … regarding the central dispatch model, the dispatch of power plants based on criteria which are different from the economic order of bids and from network constraints, giving priority to the dispatch of generation technologies”

[11] Redispatching: “means a measure, including curtailment, 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”;

[12] Central dispatching model “means a scheduling and dispatching model where the generation schedules and consumption schedules as well as dispatching of power-generating facilities and demand facilities, in reference to dispatchable facilities, are determined by a transmission system operator within an integrated scheduling process”

quo would arguably better achieve the intent of the Regulation as expanded upon in Section A above. If REFIT-supported wind with priority dispatch is not satisfied with the current approach the option is open to them to drop their priority dispatch status and submit decs at prices they believe are more reflective of their opportunity cost (in line with bidding rules). This would go some way to levelling the playing field with non-priority dispatch RES, most of which are expected to be non-firm and therefore not "kept whole" for constrained volumes in the same way that firm units (most priority dispatch units) are.[13] Retention of status quo for constraint payments would also encourage balancing responsibility and flexibility and incidentally improve DAM liquidity.

A similar perspective could be applied to interpretation of the curtailment 'compensation' provisions. Looking at Article 13(7) of the Regulation, read in isolation, on the face of it states that "financial compensation" shall be payable for non-market-based-redispatch (curtailment). While the provision states that such compensation only applies to "firm" units and goes into how the level of the compensation could be calculated, it does not stipulate whether or not and to what extent the local market landscape (e.g. extent of RES and its priority dispatch status) and its operation can be taken into account in determining: a) who to make curtailment compensation payable to; b) what the level of that compensation should be. In making this determination the TSO's operation of the system and main driver for curtailment need to be taken into account. That is to say that our understanding is that the TSO will always constrain units to maximise priority dispatch and any non-priority-dispatch units remaining on the system when curtailment arises will be thermal units for system reasons (e.g. inertia, reserves). Indeed, full implementation of Article 12 requires all non-priority-dispatch units to be able to fully participate in the market and such participation, given the role of bids, falls into the market-based-redispatch category. Article 13 then requires that, except for limited circumstances, market-based-redispatch (constraints) should always be applied before curtailment. By corollary therefore, it is only priority dispatch units that should succumb to curtailment at all. Given the intent of Article 12 and its removal of priority dispatch as well as the more future-looking facilitation of RES for decarbonisation focus of the Regulation overall there is a credible case for zero curtailment compensation to be paid, at least to priority dispatch units. Otherwise, similarly to constraint payments, a windfall could be made to existing investors to the detriment of consumers (possibly, in the case of curtailment, through imperfections charges). Furthermore, we consider that the EU is seeking to achieve non-discrimination between market participants with respect to the operation of the wholesale market. Non-discrimination does not mean treating everyone the same. Non-discrimination means that it might be appropriate to treat different things differently. In this specific example, existing RES is retaining the market advantage of priority dispatch (PD), whereas PD is being removed for future units. We therefore do not see that it would be non-discriminatory to also provide existing RES with generous compensation for curtailment; indeed, it appears that it would be non-discriminatory to not provide existing RES with generous compensation for curtailment.

Q14: Do you agree with the RAs' interpretation of Article 13(7) and the view that the provision of financial compensation to firm generators subject to curtailment based on net revenues from the day-ahead market including any financial support that would have been received represents an unjustifiably high level of compensation?

In light of our context immediately above and our general view that legislative provisions should be read holistically taking into account the drivers behind it, BGE sympathises with the RAs' interpretation of Article 13(7) and the view that the provision of financial compensation to firm generators subject to curtailment based on net revenues from the day-ahead market including any financial support that would have been received represents an unjustifiably high level of compensation. Taking the Consultation's assessment for example, that the curtailment compensation could cost between €40-140m annually, this could result in an annual increase on the current PSO levy of ~23% - 80% for curtailment alone.[14] That is not considering the additional PSO costs we are likely to see for the increasing RES coming onto the system in the next decade.[15] It is difficult to stand over such a cost to the consumer as being in line with the spirit of the CEP and this Regulation. The additional cost would arguably play no role in bolstering the business cases for new RES due to come along in the next decade as that is all expected to be "non-firm" (and thus not eligible for curtailment payments) under the Regulation. Instead the playing field would be made more uneven between existing and new RES.

BGE was involved in discussion with the RAs at industry level about what can or cannot be taken into account when determining what is "unjustifiably high" compensation. While on the face of it Article 13(7) is clear that

[13] Considering that most of the RES with non-PD will be new RES which are expected to be non-firm for the foreseeable future. Non-firm units do not get "kept whole" for volumes constrained under current market rules

[14] Based on the fact that an increase of €303.65 million (on the 2019/20 PSO levy) equated a 172.1% increase in the proposed PSO for 2020/21. https://www.cru.ie/wp-content/uploads/2020/06/2020-21-PSO-Proposed-Decision.pdf

[15] Or indeed the extra costs to the PSO should the current constraints approach under REFIT change

financial compensation for curtailment must be paid to "firm" generators, we believe that in addition to the correct interpretative approach to legislation requiring a holistic view, Article 13(7) is sufficiently ambiguous to enable an interpretation that the assessment as to what is unjustifiably high can take into account other factors aside from whether the compensation might be "unjustifiably high" only from the unit in receipt of the compensation's viewpoint. We understand also that all European regulators received guidance from DG ENER and CEER that they had scope to unilaterally determine what might be "unjustifiably high" compensation. In particular, the consumer cost referred to above is a concern and one cannot overlook the Energy Union aim of providing affordable energy to final customers. Also, of relevance is the fact that this Regulation is seeking to phase out priority dispatch. It is arguably not the Regulation's intention for payment for curtailment up to the DAM or REFIT price. As the curtailment compensation is stated to be limited to "firm" units, mainly (if not only) existing priority dispatch units will benefit from a non-contextual interpretation of Article 13(7). Again, like constraints, there is scope for a potential windfall for these units that have already invested and benefitted from considerable REFIT payments.

Q15: Which of the options on compensation for curtailment presented above do you view to be most appropriate to adopt in the SEM? Are there additional options that the RAs should consider around compensation for curtailment?

As explained in the introduction to this Section and in answer to question 14 above, there is a credible case that 'zero' compensation could be payable under Article 13(7) to firm units. Given that (a) the operation of the system should result in only priority dispatch being on the system when curtailment is actually required; and (b) that the Regulation is phasing out priority dispatch and seeking to level the playing field between participants (rather than benefitting participants for whom the market is already more favourably distorted towards), it would appear to be counter-intuitive to offer windfall payments in this respect. Akin to constraints, given the level of the set REFIT reference price, diminishing spot market prices (which trend is likely to continue), and the huge recent proposed increase in the PSO there is a case to say that wind units are already being adequately "compensated" for curtailment through REFIT also. Benefits of such an approach include the incentivisation of priority dispatch units to drop this status and more actively participate in the market, contribute to DAM liquidity, be balance responsible and flexible in line with the Regulation's intent. The unavoidable imbalance risk relating to variable RES is better managed by the generator than the consumer in our view and should be encouraged as such.

Should the RAs decide to move towards >zero payment for curtailment, the appropriate level should in our view balance the key principles of minimising consumer costs (be that imperfections or PSO charges), encouraging DAM participation and incentivising TSO investment signals in network reinforcement/ development and DS3 services. A cap on the overall compensation would be needed from a consumer perspective. With a view to providing for TSO signals to invest our preference is that the charges would most transparently be seen via the imperfections charge.

Whether the decision is to apply zero or >zero curtailment compensation to firm units, BGE urges the RAs to consider and adopt a TSO incentive that minimizes not only curtailment but also constraints. A strong signal on the need, extent of and speed of network and/ or DS3 investment is required as soon as possible and certainly before the implementation of any change in curtailment compensation levels if a change is decided upon. Ultimately, BGE would prefer to see more TSO money being spent on networks and DS3 to facilitate business cases of both new and existing units, than on just compensating existing investments further.

In terms of who curtailment compensation may be payable to, the provision appears explicit that whoever receives curtailment compensation can only be "firm" units – there does not therefore appear to be scope for curtailment compensation to "non-firm" units. While this may appear inequitable, zero curtailment compensation would go some way towards making the playing field between firm and non-firm RES more equitable bearing in mind that most new RES in the next decade will fall into the non-firm category. As mentioned in our introduction to this Section C, non-payment of generous compensation for curtailment is closer to non-discrimination between market participants, than payment of generous compensation is. This payment approach coupled with our suggested differentiation in treatment of RES in the energy balancing market whereby non-priority dispatch RES is constrained (and paid for constraints on foot of bids submitted), before any curtailment is applied (for which RES with priority dispatch need not be paid – see more in next Section), could considerably help level the playing field. We believe that the Regulation's requirement to maximise market-based-redispatch (i.e. constraints) before non-market-based-redispatch (i.e. curtailment) provides a sound legal basis for this proposed differentiated approach to treatment of curtailment and related payments.

Overall the approach could also be seen as an incentive for RES with priority dispatch to drop its PD status in line with the spirit and intent and indeed provision in the Regulation that the RAs "may" incentivise dropping PD status.

Finally, we do not support an option that sees potential intervention by the TSO earlier than real time for energy reasons.

D. Article 12 – General View and Key Questions and Answers

BGE has outlined its general position on Article 12 in Section A above. In essence the TSOs need to be armed with the necessary tools and resources to enable the full engagement in the market of non-priority-dispatch units. This means all dispatchable and non-dispatchable units should be able to submit commercial and technical offer data, physical notifications, incs, decs in accordance with bidding rules.

While the RAs do not go into much detail on the treatment of curtailment aside from suggesting continuation of the pro-rata approach, we take this opportunity to build on our suggestion under Answer 15 as to the treatment of curtailment in the market. While we agree with the continuation of curtailment on a pro-rata basis, there is an option to apply more favourable treatment to RES with no-priority dispatch than to RES with PD when it comes to curtailment. Our understanding of how the market is run by the TSO is that by the time curtailment arises, it is only priority dispatch units that will actually remain on the system to be curtailed. The reason for such is that curtailment (excess wind on the system) arises due to the concept of PD and maximising RES with PD while putting thermal generation to minimum levels (thereby 'squeezing' the middle where RES with no-PD would have sat before being constrained down). In the case of curtailment arising and RES with no PD being exposed to curtailment for some reason we are of the view that they should be constrained down based on their submitted decs and paid. Curtailment then of RES with PD could apply possibly with no payments (as discussed in some detail in answer 15 above). This approach could in our view incentivise RES with PD to drop PD and bid into the market in line with the aims of the Regulation and indeed the provision that RAs "may" incentivise units to drop priority dispatch. That should overall see a major reduction in curtailment volumes.

Q3: It is the RAs' understanding that any unit which is non-renewable dispatchable but is no longer eligible for priority dispatch can be treated like any other unit within the current scheduling and dispatch process, through submission of PNs with an associated incremental and decremental curve. Feedback is requested on this aspect of implementation of Article 12 of the new Electricity Regulation.

As outlined in Section A above, BGE is firmly of the view that the intent of the CEP and this Regulation is to facilitate renewables and simultaneously ensure that competitive wholesale markets operate as efficiently as possible. This effectively requires that as level playing field as possible between any unit without priority dispatch is achieved and balancing responsibility and flexibility is encouraged. BGE therefore agrees with the proposal that non-renewable dispatchable units no longer eligible for priority dispatch should be treated as suggested (i.e. submit physical notifications, incs, decs, commercial offer data, technical offer data etc). As outlined in Recital 25, derogations for entire technologies are no longer consistent with achieving efficient market-based decarbonisation processes. This change should also go some way to improving day-ahead-market (**DAM**) liquidity.

Q4: It is proposed that any unit which is non-dispatchable but controllable and is no longer eligible for priority dispatch would run at their FPN, <u>be settled at the imbalance price for any volumes sold ex-ante and could set the imbalance price</u>.
As part of this proposal, there is a question of whether such units would be required to submit FPNs or where no FPN is submitted, the unit could be assigned a deemed FPN calculated by the TSOs as per the process today. Where a unit elects to submit an FPN, in this case, the <u>TSOs would be required to use this as long as it does not deviate above a certain percentage of the TSOs' own forecast availability of the unit</u>.
As an alternative or as a possible interim measure, taking account of the zero marginal cost nature of non-dispatchable but controllable generation in the market today, i.e. wind, solar, units no longer eligible for priority dispatch could be scheduled to their availability as per the process today on the assumption that this reflects economic dispatch in any case, but where there is excessive generation on the system such units would be subject to energy balancing prior to any priority dispatch units.

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

Firstly, and importantly, the Consultation's phrasing of question 4 above does not entirely reflect the proposal described in the Consultation. The statement in the first sentence that they would "…*run at their FPN, be settled at the imbalance price for any volumes sold ex-ante and could set the imbalance price*" does not capture the fact that the RAs' proposal is that settlement at the imbalance price is for any deviation from volumes sold ex ante. In this context, BGE firmly believes that all units in the market that do not have priority dispatch (be they old or new) must be treated on a level playing field with all other non-priority-dispatch units e.g. conventional generation, when it comes to energy market scheduling and dispatch and constraints.

We would welcome the RA's confirmation that this is the intention here and that we do not see any reversion to 'old' SEM type rules or a softer approach to these units compared to other non-priority dispatch units.

In practice this requires that units be facilitated in submitting COD, TOD, incs, decs in accordance with balancing market bidding rules. We note the TSOs will need to revise the MW discrete steps in COD to accommodate the steps for these new units. Furthermore, they would be required to submit their own FPNs and no provision for submission by the TSO of a 'deemed' FPN should exist. Responsibility must lie with the unit. Balancing accountability should not be dampened for any such units as that would run contrary to the spirit of the Regulation. Ideally these units would be treated closer to "dispatchable" units with a view to incentivising investment in flexible or hybrid assets so reducing reliance/ responsibility on the TSO to manage intermittency and variability. By corollary, if submitting COD, TOD, and PNs like all other non-priority-dispatch units we disagree with the proposed rule that the TSOs would only use the FPN as long as it does not deviate above a certain percentage of the TSOs' own forecast availability of the unit. This undermines market-based bidding, the ability for market optimisation and the levelling of the playing field between market participants.

This approach we believe is necessary to ensure units are balance responsible and cover their need for flexibility required to participate in today's markets. It should also result in increasing DAM volumes notwithstanding that many are effectively duty bound to trade DAM under support contracts. This in turn will better allow the balancing market price signals to be maintained rather than having wind "spill" into the BM undermining the need for market flexibility.

Regarding the final aspect of this question, and the possible alternative/ interim measure, firstly BGE believes that it must be discounted as an "alternative" and considered only as an "interim" measure given how it undermines BGE principles and the intent of the CEP and this Regulation as outlined in Section A above. If the systems are delayed it may be a solution to consider[16] scheduling to TSO forecast availability (or a unit submitted FPN), apply constraint actions and pay for them before constraining or curtailing RES with priority dispatch. Rules around tie-breaks and the price of the constraint should be further consulted on once the RAs have developed their position on this further.

Q5: Feedback is invited from interested stakeholders on the treatment of non-dispatchable and non-controllable units.

BGE views on the treatment of non-dispatchable and non-controllable units are largely aligned with our view on the treatment of all other non-priority-dispatch units in terms of submission of COD, TOD, PNS, incs, decs under bidding rules as explained above.

We do not believe that there should be any "new" units (including existing units with no controllability seeking upgrades) permitted to register under this category in future as it undermines the objectives of the CEP, this Regulation and disincentivises the balancing responsibility and flexible accountability we need from all units going forward. Any soft rules or potential loopholes that would allow registration of inflexible plants in future must be avoided.

Merchant wind must necessarily be balance responsible or at least incentivised to be balance responsible. In order to facilitate the balancing responsibility however the TSO market systems and control centre changes needed must be expedited. This should see them trade DAM for commercial reasons which in turn offers a

[16] We note that alternative considerations of opportunity cost may be taken into account in bidding if receiving supports so the earlier the TSO can facilitate decs the better.

better deal for the consumer. While balancing exposure may be a new issue to contend with for many BGE believes that several routes to market such as aggregators and PPAs exist to accommodate this change.

Q6: Do you agree with the RA's interpretation that new generators which are no longer eligible for priority dispatch (both dispatchable and non-dispatchable but controllable) will be subject to energy balancing actions by the TSOs, considered in dispatch economically and settled like any other instance of balancing energy?
Q7: What is your view on the application of bids and offers to zero marginal cost generation?
Q8: What is your view on a potential rule-set being implemented for non-dispatchable units where (a), systems cannot facilitate ranking of decremental bids for such units for balancing actions for a certain time period and/or (b) where convergent bid prices require a tie-break rule?

We take these three questions together.

BGE believes that all non-priority dispatch RES should be treated the same as all other non-priority-dispatch units in that constraint decisions would be based on an economic merit-order using bids submitted in accordance with bidding rules. We need to allow them to reflect their capabilities as the balancing market must be market based and we need to reduce actions the TSO can take before real time. Tie-break issues may arise but we believe that can be addressed once the RAs have developed their thinking on the approach for all non-priority dispatch units.

BGE believes that like all other non-RES units, bids and offers should be compiled under bidding rules. Differing approaches may be applied by units in determination of what are 'opportunity costs' (e.g. between those with and without REFIT) so a ruleset needs to apply. BGE is not convinced that the current bidding rules could not be adapted for these units but would welcome further discussion once the RAs thinking on level playing field treatment for all non-priority dispatch units has developed.

We do not see a need for an alternative solution here provided the TSO is adequately equipped to adapt systems to facilitate these new non-priority dispatch players asap. However, if an alternative is necessary for system reasons, it should only apply for a limited interim period. The proposal that dispatch down of non-priority dispatch RES for constraints (which should apply on a price basis) should occur before constraining PD units seems reasonable considering otherwise it might in fact undermine the principle of priority dispatch. The appropriate price to apply however, considering also tie break implications, is something we seek further discussion on in the next steps by the RAs in this Consultation process.

E. Articles 12 and 13 – Other Questions and Answers

Q2: In terms of the practical implementation of Article 12(1) to introduce a distinction between units which retain eligibility for priority dispatch and those which are not eligible, the RAs propose;
i. Where a commissioning programme has been agreed with the TSOs on or before 4 July 2019, it is proposed that such units will be eligible for priority dispatch.
ii. Where a unit is eligible to be processed to receive a valid connection offer by 4 July 2019, the RAs are of the view that this represents a contract concluded before priority dispatch ceases to apply under Article 12 and that such units are also eligible for priority dispatch.
iii. Where a unit becomes active under a contract concluded before 4 July 2019 including a REFIT letter of offer or PPA, the RAs welcome feedback on the proposal for such generators to be eligible for priority dispatch.

Regarding the question as to whether "contracts concluded" includes each of the (iii) options above, in general BGE believes that the practical delineation between those with priority dispatch and those without must be clearly, verifiably and irreversibly determinable. BGE believes that with a view to achieving CEP and this Regulation's objectives to phase out PD, the pool of those still eligible for PD must necessarily be narrow. Our views are:

- (i) TSO commissioning programmes if readily identifiable, with agreed set commissioning dates of a relatively short timeframe, and if not subject to change by either party could be covered;
- (ii) We understand that units eligible to receive a connection offer in Ireland refers to those units under ECP-1 that have been assigned ECP-1 status – further clarification on this and who might be covered on it would be welcomed before finalising this decision;

- (iii) If it applies to those with a "specific route to market" the route must not have scope to change/ be back-dated by either party, e.g. a REFIT letter of offer may suffice.

Q10: Feedback is requested from interested stakeholders on the types of demonstration projects that may be suitable for an application process for limited priority dispatch eligibility.

BGE believes this should cover unproven technologies in the market such as are for example being discovered through the FlexTech programme. At a high level we see residential/ domestic sector technologies in the DSR space being included which would include domestic EV technology and storage.

Q:11 The RAs' interpretation of the Regulation is that where a new connection agreement is required or where the generation capacity of a unit is increased, a unit will no longer be eligible for priority dispatch. The RAs also propose that units should be able to make a choice on whether they wish to retain their priority dispatch status or not. Feedback is requested on this proposal.

Regarding the RAs' concern that the TSOs' regular processing of connection modifications often results in new connection agreements so units may be disincentivised from re-powering or increasing generation capacity, BGE is of the view that any units re-powering or increasing generation capacity would likely be doing so outside a PPA period and at that point they would have had the benefit of the PPA and supports. When they are repowering/ increasing generation capacity they should rightly be on a par energy market engagement wise with other technology types. We must see this type of 'new' RES accounting for the need to be flexible, reactive and balance responsible. No special dispensations or distortions should apply as this would undermine BGE principles and indeed the intent of the legislation as outlined in Section A above.

We agree to an extent with the RAs' proposal that units should be able to make a choice on whether they wish to retain their priority dispatch status or not provided they are already in the priority dispatch pool as at 4 July 2019. 'New' units be they brand new or repowered should not have priority dispatch status applied to them.

RAs are not incentivising units to give up PD but some of BGE's proposal we believe are an indirect incentive to drop PD and we urge the RAs to leverage on this provision in the Regulation and on our suggested proposals to optimise the market through application of the Regulation.[17]

Q9: Do you agree with the TSOs' proposal for a revised priority dispatch hierarchy? The RAs request that the TSOs consider the points raised in this Section in their response with any further proposed changes to the hierarchy.

We would welcome further clarity on the decisions behind the alteration of the priority dispatch hierarchy and also where exactly RES with no-priority dispatch sits in the diagram/ levels noted; including on an interim basis.

Q12: Do you agree with the RAs' interpretation of Article 13(5)(b) whereby downward redispatching of electricity produced from renewable energy sources or from high-efficiency cogeneration (i.e. the application of constraints and curtailment) regardless of priority dispatch status, should be minimised in the SEM? Under this interpretation, the only difference between renewable generators and HECHP eligible for priority dispatch will be how they are treated in terms of energy balancing.

From a plain reading of the Article, read in isolation, the above would appear to be the case but it seems to conflict with the principle of priority dispatch and the levelling of the playing field between RES and non-RES units as intended by the CEP and the Regulation itself. This is an example where a provision must necessarily be read in the wider context of the provision and the Regulation itself. The provision itself states that "*appropriate grid-related and market-related operational measures in order to minimise the downward redispatching of electricity*" from RES and HECHP shall be taken. The important word here is "appropriate" and in the wider context of the CEP and BGE principles (not least being market integration and levelling of playing field) we do not believe that this provision impacts on the proposals suggested by BGE in our replies above. It does not suggest that any additional priority in dispatch for RES or HECHP that does not have priority dispatch as of 4 July 2019 should apply. Rather, read with the purpose of the Regulation in mind, we believe the onus under

[17] For example, a) retention of the current operation of constraint payments in the market and under REFIT, b) consideration of a zero-curtailment compensation option, would both incentivise a unit to drop its Priority Dispatch status and participate in the market on a more level playing field and become balance and flexibility responsible

Article 13(5) in general is on the SOs to ensure wires and DS3 services are developed to maximise facilitation of all RES and if that is achieved then redispatch down of RES and HECHP will by corollary be minimised. In this context the question arises again as to whether potential additional compensation money could be better spent by the TSOs in developing the network and DS3 services to cater for the increasing new RES we need on the system to meet 2030 targets

Regardless of a unit's commissioning date (so whether it has priority dispatch or not isn't relevant), all RES followed by high efficiency co-gen should only be subject to curtailment where other solutions would result in significantly disproportionate costs or severe risks to network security.
Q13: Do you agree with the RAs' interpretation of Article 13(6) and the introduction of a new hierarchy for the application of non-market-based downward redispatching?

In light of our discussion above[18] and the scope to better level the playing field between RES with no priority dispatch and RES with priority dispatch, we believe that curtailment arises on foot of the priority dispatch concept and thus that it is only priority dispatch RES that will be on the system to be curtailed. The hierarchy appears to be logical when you consider that all non-RES and RES with no priority dispatch will in fact be 'constrained' before any curtailment is deemed to arise. When curtailment then does arise, it is only RES with priority dispatch that should be affected by curtailment based on our understanding of the operation of the system. The hierarchy may need to be altered to reflect this reality.

F. Summary and Conclusion

We outline below a summary of BGE's position and rationale for key issues in this Consultation before going on to conclude on the overall approach to decisions arising from this Consultation and possible next steps.

In summary:

i. We agree with the RAs' distinction on the **definition of "redispatch"** between constraints and curtailment. The RAs' rationale together with additional views outlined in our answer to Question 1 under Section B above suitably justifies the interpretation that market-based-redispatch is akin to constraints in SEM and non-market-based redispatch is akin to curtailment in SEM;
ii. BGE believes that the well-known "**purposive approach" to applying EU legislation** should be applied by the RAs in implementing / applying Articles 12 of 13 of this Regulation. This in our view requires a reliable holistic application of the provisions in question whereby key aims of the Energy Union, including decarbonisation and the levelling of the playing field amongst all market participants, need to be achieved but in a manner that ensures affordability of energy to the end consumer;
iii. The levelling of the playing field intent applies to both market participants with and without priority dispatch. It is clear from the Regulation's provisions that favourable treatment afforded to some units over others (e.g. those with priority dispatch) must be avoided insofar as possible. Those in receipt of government subsidies should be treated in a manner that does not impede or interfere with the efficient operation of a competitive wholesale electricity market. This in our view allows the conclusion to be drawn that **RES with priority dispatch in receipt of government supports such as REFIT**, are already being adequately "compensated" for both constraints and curtailment. Additional payments that would effectively result in a 'windfall' payment to existing investment cases amounts to more favourable treatment being applied to these units that already have favour applied to them over others. Maintaining the status quo for constraint payments would incentivise RES with priority dispatch to drop its priority dispatch status, better level the playing field, encourage balancing responsibility and flexibility and incidentally improve DAM liquidity in line with the aims of CEP and this Regulation. Please see our general views at the start of Section C above for further details;
iv. Equally, given the desire to ensure balancing responsibility, encourage flexibility and level the playing field additional revenue beyond what currently applies through either constraints or curtailment compensation to **merchant units with priority dispatch in the market** is not necessarily warranted. This is on foot of the

[18] Please see the start of Section D, general BGE comments where we propose constraining of all RES and non-RES with no priority dispatch (on a price basis) before curtailment of priority dispatch units is considered at all

fact that these units would have already benefited from 15 years of government supports and current SEM systems would treat them for constraints similarly to non-RES units which is highly conducive to levelling the playing field. Similarly, we do not believe curtailment payments are necessarily warranted to these units given the years of financial support their business cases have already benefited from at the cost of the consumer. Applying curtailment compensation would unnecessarily bolster their investment cases placing them at an unfair advantage to units with no priority dispatch status (most of whom will be non-firm and not entitled to curtailment compensation), contrary to the intent of the Regulation. The resulting impact to imperfections charges when it comes to curtailment, which consumers would bear, is difficult to justify in the general spirit of the CEP. Please see Section C and answer 14 for further details;

v. Staying on the point of curtailment, BGE's view is that the TSO operates the system such that it is the priority dispatch concept that results in curtailment arising at all. Consequently, it is **only RES units that have priority dispatch that should remain on the system when it comes to curtailment** given that all other RES units should have been constrained before that. This should certainly be the case when the systems can cater from incs, decs from non-priority dispatch units which by virtue of their inc, dec price submission places them in the category of market-based-redispatch (constraints). Under the Regulation constraints must apply as much as possible before curtailment is considered. With a view to levelling the playing field between RES with priority dispatch who are well protected from balancing responsibility and RES with no priority dispatch, BGE urges the RAs to consider applying constraint actions (that are paid) to RES with no priority dispatch before curtailing only RES with priority dispatch (which need not be paid for). This should also be the case on an interim basis. The Regulation's requirement to maximise market-based-redispatch (i.e. constraints) before non-market-based-redispatch (i.e. curtailment) provides a sound legal basis for this proposed **differentiated approach to treatment of curtailment and related payments**.

vi. Furthermore, maintaining the status quo for curtailment compensation could **incentivise RES with priority-dispatch to drop its PD status (which incentivisation is provided for in the Regulation) and overall reduce curtailment volumes.** We consider that the EU is seeking to achieve non-discrimination between market participants with respect to the operation of the wholesale market. Non-discrimination means that it might be appropriate to treat different things differently. In this example, existing RES is retaining the market advantage of priority dispatch (PD), whereas PD is being removed for future units. We therefore do not see that it would be non-discriminatory to also provide existing RES with generous compensation for curtailment; indeed, it appears that it **would be non-discriminatory to not provide existing RES with generous compensation for curtailment**. Please see Section C and answer 15 above for further details;

vii. BGE sympathises with the approach the RAs have taken to determining what is an **"unjustifiably high" cost of curtailment.** We believe there is a level of ambiguity in Article 13(7) and understand DG ENER and CEER guidance supports the RAs' approach to determination. Should the RAs move from a zero compensation for curtailment approach, the level should best balance minimisation of consumer costs (PSO and imperfections), encouragement of DAM liquidity and incentivisation of TSO investment in networks and DS3 services. A cap on overall compensation for curtailment is deemed necessary from a consumer cost exposure perspective. A strong TSO incentive to minimise constraints and curtailment and focusing TSO spend on networks and DS3 is arguably preferable to compensating existing investments further. Please see answer 15 and the start of Section D above;

viii. We urge the RAs to **ensure that the TSOs implement the necessary systems to enable RES without priority dispatch to participate in the market** as early as possible. All dispatchable and non-dispatchable units should be able to submit commercial and technical offer data, physical notifications, incs, decs in accordance with bidding rules. There should be no soft-rules or loopholes that would allow for the continuation of distortion of market operation by virtue of different treatment of units within the market. No provision should remain for the TSOs to apply TSO-determined FPNs – instead each participant with no priority dispatch should be permitted to submit FPNs of their own determination which should then be the starting point in dispatch by the TSOs as is the case for any non-RES non-priority dispatch unit. This would best meet the aims of balancing responsibility, flexibility and DAM liquidity (which minimises consumer costs). Only on a very short-term interim basis might a TSO-determined FPN be acceptable until systems are ready. Constraints would therefore be applied to RES with no priority dispatch akin to non-RES with no priority dispatch, on a market basis. A bidding ruleset needs to apply, and we believe the detail of this, given for example different views units might have on opportunity costs, should be included in the next stage of this Consultation process. We do not agree with enduring alternative solutions but could see how on a short interim basis, the constraining of non-priority dispatch units for constraints on a market basis before constraining units with PD could work so as not to undermine the concept of priority dispatch. Please see Section D and answers 3-8 above for further details;

ix. **Constraints should be applied on a price basis to all non-priority-dispatch units before curtailment** is considered only for priority dispatch units. The price of the constraint on the interim basis discussed immediately above and rules around tie-breaks should also form part of the RAs' next steps in this Consultation process;

x. There should be **no scope for new units in future to be able to register as non-controllable** as it would undermine the balance responsibility and flexibility aims of the CEP;

xi. To accommodate **merchant units that do not have priority dispatch**, the TSO systems and national control centre changes needed to accommodate their market interaction should be expedited. Benefits should materialise in DAM liquidity and consequently consumer costs. The management of new balance responsibility can be facilitated by the many routes to market that exist such as via aggregators, intermediaries and PPAs. Please see Section E above;

xii. In deciding on the cut off contracts for **what units fall within priority dispatch before 4 July 2019**, BGE believes that the practical delineation between those with priority dispatch and those without PD must be clearly, verifiably and irreversibly determinable. It should allow no scope for back-dating and in this regard a REFIT letter of offer is a good example. PPAs are thought to be too 'soft' and TSO commissioning programmes and those eligible to receive a connection offer could be acceptable provided their operation date is relatively near and time limited. Please see Section E above;

xiii. **Demonstration projects that may be suitable for limited priority dispatch** eligibility could cover unproven technologies in the market, e.g. in the FlexTech programme. DSR technologies including domestic EV technology and storage are other examples;

xiv. We do not believe that **units that are re-powering or increasing their generation capacity** should be permitted to retain priority dispatch. It is likely at this point that they will have benefitted from several years of government supports and the EU aim of incorporating them in the market in terms of being balancing and flexibility responsible would point to the need for them to drop priority dispatch status. Please see Section E above;

xv. We would welcome further insight from the TSOs and in the RAs' next steps on this Consultation process on the decision behind **the new priority dispatch hierarchy** and any interim application plans;

xvi. Article 13(5), when read in the context of the Regulation's aim, in our view puts an **onus on the TSO to ensure the wires and DS3 services are at such a level that minimisation of RES and HECHP will be the end result**, rather than a straight priority being given to RES or HECHP given how, read in isolation, that would conflict with other aims such as removing priority dispatch. It thus follows that focusing TSO spend on the wires and DS3 services may better serve this end goal rather than for example spending additional money through constraints or curtailment for existing units.

In conclusion in general BGE believes that the RAs' approach of taking into account the current market systems and processes and the affordability of energy to end consumers, when deciding on the appropriate solutions for the application and implementation of Articles 12 and 13, to be an appropriate starting point for this decision-making process. We would welcome early insight on the timings for the RAs' decision-making process and priority in terms of what decision may be made at what point in time and with further consultation.

I hope you find the above views and suggestions helpful but please do not hesitate to contact me should you wish to discuss any element at all further.

Yours sincerely,

Julie-Anne Hannon
Regulatory Affairs – Commercial
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{By email}