BY EMAIL ONLY
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Response to consultation on Implementation of Regulation 2019/943 in Relation to Dispatch and Redispatch

A chara,

innogy are pleased to have the opportunity to provide comments to the above consultation. Innogy Renewables Ireland Ltd (IRIL) was established in 2016 and is owned by innogy SE, a leading European energy company.

In Ireland, innogy are active in the development of our Onshore and Offshore wind and battery storage project pipeline. innogy operate a 10MW windfarm at Dromadda Beg in Co. Kerry and we are in the process of growing our onshore wind pipeline to include new greenfield developments, consented sites and operational wind farms. In March 2018, innogy acquired an equal share in the Dublin Array Offshore Wind Farm Project, partnering with another Irish company, Saorgus Energy. In January 2020, innogy confirmed it will proceed with the installation of a 60MW battery storage project in Co Monaghan and most recently, the 8.5MW battery storage project in Stephenstown.

Whilst we welcome the publication of this consultation as the first engagement, there are many aspects of the proposed implementation which we disagree with, and which we believe will require significant further engagement and consultation to deliver an effective, efficient and fair implementation of the new Regulations.

Our biggest concern remains the lack of a detailed, costed and realistic programme to ensure that all new (non-priority, non-dispatchable) renewable generation will be able to submit commercial offer data which will allow such sites to be dispatched and re-dispatched on a market basis. This would deliver the benefits of reducing the likelihood of increased levels of [local] constraint and [system wide] curtailment – thereby reducing the future burden on energy consumers.

As a keen proponent of market-based solutions, we are very concerned with some aspects of the consultation, in particular "interim" solutions which do not address the need for market based operation nor provide a timescale for the delivery of a fully effective market operating system designed to effectively and efficiently manage the future composition (renewable) Irish generation fleet.Please find attached our comments in response to this consultation.

If you wish to follow up this response please get in touch with innogy's Policy Manager kate.garth@innogy.com or myself.

Le meas,

Cathal Hennessy
Innogy Renewables Ireland Limited

Section 1 – Clean Energy Package Background and overview of requirements of Arts 12 &13

Q1) Do you agree with the RA's 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?

We have some reservations about the interpretation of the requirements under Articles 12 and 13 which will be covered in more detail in the later questions (particularly around the proposed eligibility to retain priority dispatch). In summary, regarding the interpretation of the specific terms used within the Electricity Regulations:

- We agree with the interpretation of dispatch and redispatch as set out in Table 1 (page 16).
- We agree with the interpretation of curtailment as a non-market based redispatch.
- We do not agree with the [current] interpretation of constraints as a market based mechanism for controllable but not dispatchable renewable assets, given the lack of Commercial Offer Data (COD) / Technical Offer Data (TOD) and Final Physical Notifications (PNs and FPN) currently utilised. In future when the new (non-dispatchable but controllable) sites are able to provide this data, and the System Operators treat them on an equal basis to other generation, only then should constraints be considered market based redispatch.

Section 3 – Proposals for implementation of Art 12

3.1 Eligibility for Priority Dispatch

Q2) In terms of the practical implementation of Art. 12 (1) to introduce a distinction between units which retain eligibility for priority dispatch and those which are not eligible, the Ras propose:

- *Where a commission programme has been agreed with the TSOs on or before 4th July 2019, it is proposed that such units will be available for priority dispatch*
- *Where a unit is eligible to be processed to receive a valid connection offer by 4 July 2019, the RAs are of the view that this represents a contract concluded before priority dispatch ceases to apply under Article 12 and that such units are also eligible for priority dispatch.*
- *Where a unit becomes active under a contract concluded before 4 July 2019 including a REFIT letter of offer or a PPA, the Ras welcome feedback on the proposal for such generators to be eligible for priority dispatch.*

Interested stakeholder's views are invited on these proposals.

We agree with the first bullet point; (where a commission programme has been agreed with the TSO on or before 4th July 2019) – that those sites should retain priority dispatch.

We also agree with the third bullet point; where a unit becomes active under a contract concluded before 4 July 2019 (including a REFIT letter or PPA), that those sites should retain their right to priority dispatch – so long as the site meets all the required milestones. Should the unit fail to meet its contractual requirements (as set out in their offer of letter, or in the case of a capacity market agreement or DS3 service agreement) – their eligible access to Priority Dispatch should be removed.

However, we strongly disagree with the proposal set out under the second bullet point: (*to allow units eligible to be processed to receive a valid connection offer by 4 July 2019*) to have priority dispatch status.

As a matter of law, for a contract to exist, there must be a valid offer and acceptance. A generator that is *eligible* to be processed for a connection offer does not have *an enforceable legal right to receive* a connection offer, let alone an enforceable connection agreement.

Once a connection offer is issued, a generator typically has 90 days to accept it and the generator must satisfy any specified conditions precedent before the offer is considered to be validly accepted. The conditions precedent will include:

- making a first stage payment,
- putting in place any bonds required by the system operator, and
- countersigning and returning the connection offer to the system operator.

All of the conditions of acceptance must be satisfied before there can be a legally binding agreement in place.

The wording of Article 12.6 states:

12.6) Without prejudice to contracts concluded before 4 July 2019, power-generating facilities that use renewable energy sources or high-efficiency cogeneration and were commissioned before 4 July 2019 and, when commissioned, were subject to priority dispatch under Article 15(5) of Directive 2012/27/EU or Article 16(2) of Directive 2009/28/EC of the European Parliament and of the Council (20) shall continue to benefit from priority dispatch.

If (the relevant contracts are Connection Agreements, (which we believe that they cannot be), as a matter of law the reference to "contracts concluded" must be interpreted as contracts that are legally binding and therefore cannot include

(1) generators who are eligible to be processed for a connection offer; or
(2) generators who have received a connection offer which may or may not be validly accepted.

We would also strongly argue that if a grid connection offer had not been accepted by the site prior to the 4th July 2019, then the site should no longer eligible for priority dispatch. It will also be important to ensure that any previous connection offers (such as Gate 3), if the connection agreement is significantly modified should also lose their access to priority dispatch (please see our response to question 12 for more details).

3.2 Treatment of "new" renewable units in scheduling and dispatch

Q3) It is the RAs understanding that any unit which is non-renewable dispatchable but it 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 the implementation of Article 12 of the new Electricity Regulation.

We agree.

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, be settled at the imbalance price for any volumes sold ex-ante and could set the imbalance price.

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

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

For clarity – we assume that question 4 should read:

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, and any difference between the traded and metered volume would be settled at the imbalance price ~~for any volumes sold ex-ante and could set the imbalance price.~~

We note there is not an explicit question in the consultation seeking views on the more fundamental nature of the future market, within which a large (and increasing) proportion of new controllable but non-dispatchable renewable generation will emerge. We agree with the premise set out on page 29 (section 2) that a new category of non-dispatchable but controllable renewable generators should be created.

There should be no assumption by the TSOs that the system used would be EDIL if that system is not capable of properly accommodating renewable generation through automation of higher frequencies of reforecasts and traded positions. We would not want to see a "shoe-horning" of future electricity generation into an old, inflexible system which does not and cannot meet the requirements of the new generation technologies.

With respect the subsequent three bullet points, please see the specific comments below.

Bullet point one:

We agree that for non-dispatchable but controllable units which no longer qualify for priority dispatch would run in line with their FPN and submitted commercial offer data, but that any volume deviation from their traded position would be settled at the imbalance price and that that imbalance volume could set the imbalance price. However, we are very concerned at the suggestion that the FPN could be adjusted by the TSO if it believed it did not match (presumably within a tolerance) the TSOs forecast of that site's availability. This seems to run counter to the intention to require units to be balance responsible, and could suggest a level of information asymmetry, therefore adding risk.

We would also suggest that in order to meet the wider criteria of ensuring market participants have balance responsibility (as set out in Article 5.1 of the Regulations), there should be no expectation that new sites (which no longer qualify for priority dispatch) would be able to participate within the market without submitting COD. This will become particularly important in any future market with negative pricing and will be critical to ensuring all these new units are able to provide bids and offers, and therefore face market based dispatch and redispatch decisions. (This would also have the benefit of reducing the level of curtailment necessary), as sites would commercially chose not run when there is likely to excess generation and risk of negative pricing.

We would also note that this would / could result in the TSOs having to manage separate processes and potentially develop multiple system changes to accommodate these separate approaches, which would likely require additional time and cost.

Bullet point two (Interim Solution)

We do not agree with the proposed alternative or interim measure, as this will not address the need to develop a market based approach for new renewable non-dispatchable sites, which will no longer qualify for priority access. It will (as also mentioned in the above response) risk sites running when the market has negative pricing. It also does not address the issue that the current TSO systems cannot accept commercial offer data (COD) or Technical Offer Data (TOD), both of which would be required to enable the interpretation of constraints to be considered market based redispatch.

Whilst we fully recognise the imperative of ensuring the ISEM is made compliant with the recast Electricity Regulations, it must be done in a way which doesn't discriminate new renewable generation nor risk creating problems for the future efficient working of the market.

If an interim measure is required (due to the current TSO system constraints) this will need to be consulted upon in full (how long the interim measure will last and how this will impact new renewable (dispatchable but not controllable)_ sites. This would also mean [by definition] that constraints would need to be treated as non-market based redispatch and therefore eligible for compensation for those sites with firm access, whether they are priority dispatch sites or not, as not to do so would be discriminatory.

Bullet point three

Whilst we note this question is more directed at the TSOs and the changes necessary to enable their systems to comply with the new Electricity Regulation, we are keen to ensure that future system designs which would enable non-dispatchable renewables to fully participate are not discounted because they would take longer to implement.

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

No Comment.

Section 3.6 – Treatment of "new" renewable units in energy balancing

Q6) Do you agree with the RAs 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?

In principle yes – we agree with the RAs interpretation that new generators which do not qualify for priority dispatch would be subject to energy balancing actions, considered in economic dispatch and settled like other instances of balancing energy. However, how this can or will be achieved and over what timescales is not currently clear.

Before any decision can be made, it will be important to ensure that the market systems can dispatch these new market participants in an economic way. This must include the ability for market participants to provide the necessary COD, FPNs and be able to interface with market operating systems in a non-discriminatory way.

Q7) What is your view on the application of bids and offers to zero-marginal cost generation?

As commercial entities, participating in a competitive market, we would strongly advocate that they system ensures that all non-priority dispatch generators are able to submit bids and offers (irrespective of whether the generator has a zero marginal cost).

Where a generator is subject to market based redispatch, the generator must be able to bid a price at which it is prepared to be redispatched. In doing so, it will bid the price at which its opportunity cost (or cost, as the case may be) associated with the redispatch is covered.

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?

This question will (to a large extent) be impacted by the length of time likely to introduce a suitable system that will accommodate economic bidding by non-dispatchable generators. Without this information we can only suggest the high level principle approaches below:

There should be no expectation that for new (non-dispatchable sites) that the system would be unable to facilitate decremental bids. Such sites must be able to bid in the incremental and decremental offers for their generating sites.

In the event that convergent bid prices are submitted, if they are in merit - we would anticipate these would be dispatched accordingly. It would only become an issue if the required reduction exceeded the volume available from the "new" non-dispatchable sites and that existing priority dispatch sites were required to be reduced.

<u>Section 3.4 – Proposed Revisions to Priority Dispatch Hierarchy</u>

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.

The proposed hierarchy is:

1) market position allocated based on cleared ex ante and balancing market trades for all participants that solves energy balancing and <u>SNSP restrictions</u>
2) if those market positions need to be dispatched down - then HECHP / biomass / waste are set to minimum generation levels
3) Then Wind, solar, tidal and hydro sites (with different nuances for controllability of wind)
4) Dispatch down HECHP / Biomass / waste to energy etc to off
5) interconnector schedules
6) generation the dispatch down results in a safety issue for people (hydro flood risk)

We welcome the confirmation provided by the RAs that they too have some concerns regarding point 1; market position is allocated based on cleared ex ante and balancing market trades for all participants that solves energy balancing and <u>SNSP restrictions (which would be curtailment for system need)</u>, as we agree that SNSP is not the only cause of curtailment and shouldn't be treated separately.

We would also ask for clarification as to the proposed treatment of the remaining peat plants.

Section 3.5 – Priority Dispatch for certain new Eligible Units

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.

With regards to the information set out in the consultation, we do not yet have a view as to what would or could constitute a demonstration project which may be suitable for priority dispatch in line with the criteria as set out in the Electricity Regulations. We would suggest the RAs provide clarity as to how long the priority dispatch status could last (is it for the duration of the project / funding) and thereafter revert to non-priority dispatch status, and how the RAs would seek to ensure that the demonstration project meets the criteria (as shown below):

"a project which demonstrates a technology as a first of its kind in the Union and represents a significant innovation that goes well beyond the state of the art".

Section 3.6 – Cessation of Eligibility for Priority Dispatch

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

6. Without prejudice to contracts concluded before 4 July 2019, power-generating facilities that use renewable energy sources or high-efficiency cogeneration and were commissioned before 4 July 2019 and, when commissioned, were subject to priority dispatch under Article 15(5) of Directive 2012/27/EU or Article 16(2) of Directive 2009/28/EC of the European Parliament and of the Council (20) shall continue to benefit from priority dispatch. Priority dispatch shall no longer apply to such power-generating facilities from the date on which the power-generating facility becomes subject to significant modifications, which shall be deemed to be the case at least where a new connection agreement is required or where the generation capacity of the power-generating facility is increased.

We agree that the Regulations are clear that priority dispatch would no longer apply to:

such power-generating facilities from the date on which the power-generating facility becomes subject to significant modifications, which shall be deemed to be the case at least where a new connection agreement is required or where the generation capacity of the power-generating facility is increased.

However, we believe that the emphasis and intent of Article 12.6 relates to the significant modification of the generating facility – which would either be evidenced through an increase to the generating capacity of the site or the need for a new connection agreement.

We do not accept the interpretation that a new connection agreement could automatically result in the loss of priority dispatch, given that new connection agreements are often issued following administrative changes (such as name change or ownership change) which have no impact on the generating facility itself and would not meet the criteria of a significant modification.

Our preference would be RAs to explicitly set out what would constitute a significant modification, other than changes which result in the generation capacity being increased, as we believe that policy intent is clear in the regulations and it will be important to ensure the right policy intent is implemented.

Section 4 – Proposals for implementation of Article 13

Section 4.2 Facilitation of renewable energy sources and high efficiency cogen in redispatch

Q12) Do you agree with the RA's interpretation of Article 13.5 (b) whereby downward re-dispatching 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.

We fully agree with the RA's interpretation of Art. 13.5 (b) – and salute the principle that the TSOs should aim to minimise the application of constraints or curtailment in the SEM to renewable generators and HECHP (particularly given the need to increase delivery of RES-E in Ireland to 70% final demand by 2030 and in Northern Ireland, to support the UK's net zero by 2050 target). We also fully support the principle that this would apply to all renewable generators or HECHP, regardless of their commissioning date and that therefore there is no distinction between units with priority dispatch or non -priority dispatch

We would also note that for new (non-dispatchable sites), assuming they are able to submit commercial offer data and FPNs would provide a market based redispatch.

Section 4.3 – Introduction of a non -market based downward redispatch hierarchy

Q13) Do you agree with the RA's interpretation of Article 13.6 and the introduction of a new hierarchy for the application of non-market based downward redispatching.

The hierarchy proposed is (subject to the risk of disproportionate costs, network security issues and available solutions):

1. Application of non-market downward re-dispatching to all classes of generation except renewable energy sources and HECHP
2. Application of non-market downward re-dispatching to HECHP.
3. Application of non-market downward re-dispatching to renewable energy sources.

It is not entirely clear to us why the hierarchy proposed in the consultation (for non-market based redispatch) would be different to the hierarchy proposed on page 34 of the consultation, given that the new (non-dispatchable but controllable sites) will be subject to market based redispatch (noting the caveat that the system will need to be modified to enable and deliver market based redispatch).

Section 4.4 Curtailment in the SEM and Article 13.7

Q14) Do you agree with the RA's 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?

No, we do not believe that the provision of financial compensation to firm generators subject to curtailment (based on net revenues from the DAM including any financial support that would have been received) would constitute an unjustifiably high level of compensation. Given that the consultation states that only curtailment is non-market based redispatch, which is by definition a system wide issue that is not impacted by local issues (and therefore the "firmness" of the connection is irrelevant) we strongly argue that all curtailed generation (whether firm or not firm) should be eligible to receive compensation.

We would also note that this should not be an issue for any new (non-dispatchable but controllable RES-E) sites, as they will [must] be able to submit commercial offer data with submitted bids/ offers and FPNs which should be used as a market-based redispatch in future.

We are concerned that if the RAs set out parameters of what constitutes unjustifiably high (or low) compensation based on the costs to consumers – this will not remove the problem, but simply shift it to a more risky and less transparent process, as generators will have to start to factor in the risk of no compensation resulting from curtailment (and increasing levels of curtailment) and constraints as non-market based redispatch.

Given the TSOs are more likely to have full access to the degree and likelihood of curtailment and constraint, they would be best placed to manage that risk (and should be incentivised to do so). We do not welcome the apparent trade-off between funding for investment in system services and the DS3 programme and an appropriate level of compensation for non-market based redispatching in the SEM.

We would argue that both are required until the system is fully capable of running on low or zero carbon generation and to create an artificial divide been providers of energy and system services could further complicate the investment outlook for Ireland and lead to sub-optimal outcomes.

Section 4.5 Options under 13.7

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?

We would again note that the need for compensation would only apply to sites which are curtailed due to non-market based redispatching. This would; (assuming the right system changes are delivered in a timely fashion to enable all new non priority dispatch (non-dispatchable but controllable) sites to submit commercial offer data and FPNs, mean no compensation would be required – as the generator unit would bid in a price at which it is prepared to be re-dispatched – (ensuring the site operator is fully compensated for any redispatch necessary).

Where non-market based redispatch is required, Article 13(7) ensures that the compensation received by a generator that is subject to non-market based dispatch is no less than the remuneration received by a generator that is subject to market based dispatch. This is important for a range of reasons, including that generators are not prejudiced by a failure of a Member State to implement market-based mechanisms for redispatch as envisaged by Article 13(2); Member States are not incentivised to opt for non-market based rather than market based Redispatch mechanisms in breach of Article 13(2); and perhaps most importantly, markets are not designed with structural barriers to development of renewables and achievement of the EU's climate objectives. In order to ensure that these objectives are achieved, it is critical that Article 13(7) is implemented in Ireland as intended.

In all cases, Article 13(7) contains an absolute requirement that (i) a generator that subject to non-market based redispatch is compensated by the system operator; and (ii) that the level of compensation is at least equal to the higher of the actual costs associated with the redispatch or the opportunity cost associated with the redispatch, save where this results in unjustifiable over or under compensation to the generator.

Furthermore, until there is a wider discussion and consultation on the proposals (and future modifications necessary for implementation) relating to market access for nonpriority, non-dispatchable but controllable sites in future, we are unable to assess how the options would work in the future and interact with wider market mechanisms.

As such we do not support the proposals set out within Options 1 -7, as these do not comply with either the wording or intent of Article 13.7 and an assessment of the commercial risks is not possible at this time.