Energy for generations

esb.ie

Giniúint agus Trádála
Two Gateway, Bóthar An Phoirt Thoir
Baile Átha Cliath 3, D03 A995, Éire
Fón +353 1 676 5831

Generation and Trading
Two Gateway, East Wall Road
Dublin 3, D03 A995, Ireland
Phone +353 1 676 5831

ESB Generation and Trading Response:

Consultation on Dispatch, Redispatch and Compensation Pursuant to Regulation EU 2019943 (SEM-21-026) and Proposed Decision on treatment of new renewable units in the SEM (SEM-21-027)

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1. INTRODUCTION

ESB Generation and Trading (GT) welcomes the opportunity to respond to the Regulatory Authorities consultation on Dispatch, Redispatch and Compensation Pursuant to Regulation EU 2019943 (SEM-21-026) and Proposed Decision on treatment of new renewable units in the SEM (SEM-21-027). The purpose of this Consultation Paper is to consult on the minded to position in relation to specific areas raised in the Consultation Paper, SEM-20-028, related to the implementation of Articles 12 and 13 of the Electricity Regulation[1], focusing on the definitions of dispatch, redispatch and non-market based redispatch in the SEM and arrangements for compensation under Article 13(7). The purpose of the proposed decision Paper is to consult on the Regulatory Authorities' proposals concerning the treatment of new renewable units in the SEM. ESB GT's response is laid out into three sections; the first is an executive summary of ESB GT's response to the Consultation Paper and Proposed Decision, the second section lists ESB GT's comments on the RAs proposed decisions and questions (SEM-21-026), and the third section lists ESB GT's comments on the RAs proposed decisions (SEM-21-027).

2. EXECUTIVE SUMMARY

Firstly, ESB GT welcomes the extension provided by the SEM Committee (SEMC) on the consultation period. However, ESB GT asks that it be acknowledged that the number of consultations over the same period has been an extremely difficult ask and one that is not conducive to ensuring the most optimum response from industry members on such material topics. In future ESB GT hopes that a schedule of expected consultations and their related timeframes can be published ahead of publication to support the industry in managing its resources.

Considering the SEM Committee (SEMC) position on the need to apply a bidding code of practice and the SEMC approved EirGrid definition of constraints, it would appear that any redispatch action on a non-priority dispatch unit is non-market based as per Article 13(3)(c) where it states "*Non-market-based redispatching of generation, energy storage and demand response may only be used where:..(c) the number of available power generating, energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located*;". Following further review of the Clean Energy Package (CEP) Article 13 and the SEMC decision on the distinction between constraints and curtailment (SEM-13-011), it is ESB GT's view that the redispatching due to constraints can only be viewed as non-market based.

In terms of the proposed position on compensation for redispatching, it is ESB GT's view that the current experiences from the market have highlighted the need to reconsider any potential transition from BCOP to BMPCOP and that the application of the BCOP is in compliance with Article 13 in that it allows participants to reflect the true opportunity cost of the TSO action in decremental prices. ESB GT believes the SEMC have the ability to satisfactorily and quickly implement the CEP Article 13 by identifying all redispatch actions as non-market based and allow non-priority dispatch renewable units to reflect their opportunity cost in both their simple and complex COD through the continued application of BCOP. Such an approach would ensure equal treatment, under the current rules, for non-priority dispatch units (renewables and thermal).

ESB GT questions the consumer benefit when prohibiting the recovery of the full support value in redispatching and the potential implications it could have on the RESS strike price. The increased risk of this inability to recover costs through competitive bidding set out in the proposed decision may be reflected in future RESS strike prices meaning the consumer takes on an increased risk profile.

[1] EUR-Lex - 32019R0943 - EN - EUR-Lex (europa.eu)

Under the current proposal, to allow compensation to DAM revenues for curtailment on non-priority dispatch renewables, ESB GT does not believe the value of priority dispatch has been reflected and that there isn't an incentive for units to voluntarily give up priority dispatch. A truer reflection of the value of priority dispatch may be non-priority dispatch units being allowed to reflect the value of their full level of support in the simple and complex COD. ESB GT believes if non priority dispatch units are compensated to the full level of the support mechanism than priority dispatch units may be incentivised to give up priority dispatch status while at the same time accomplishing the decarbonisation agenda. This approach ensures that the correct incentive is introduced rather than a retrospective imposition limiting bids and increasing risks for RESS1 contracted plant. This opportunity to have a choice retains the principles of competition and allows effective business decision making.

In terms of moving forward in the interim, the severity of system changes may be reduced if redispatching non-priority dispatch units is viewed as non-market based and compensated to the full level of support.

In relation to a potential SNSP/constraints cap in the ex-ante markets, ESB GT agrees with the RAs that the introduction of such a cap could be discriminatory to certain types of generation to which the cap would be applied and may not be fully compliant with the requirements of Article 13(7) to provide compensation for non-market based redispatch.

In summary, ESB GT does not support the current proposal that non-priority dispatch renewables units which are redispatched due to constraints with their commercial offer data subject to BCOP or BMPCOP, that prohibits the recovery of the real opportunity costs of the full support, can be viewed as market based redispatch. The definition of constraints currently applied in SEM clearly identifies that a constraint "*could only be resolved by reducing the output of one or a small group of price taking generation*" which aligns with the definition of non-market based redispatch in Article 13(3)(c).

3. COMMENTS ON CONSULTATION PAPER SEM-21-026

In this section ESB GT has highlighted some of its concerns with this consultation and compliance with the Clean Energy Package (CEP) Article 13.

3.1 Grandfathering of Constraints (Market Based Redispatch).

If the SEMC's view that BCOP/BMPCOP, and not reflecting the support mechanism revenues, is to be applied as bid restrictions to redispatch actions on non-priority dispatch renewable units it is difficult to see how redispatch of such units can be anything other than non-market based redispatch for the following reason:

- The SEMC are of the view that the definitions of constraints are, as per SEM-13-011; "*If the Control Centre assumed it had control over every price taking generation unit in tie break on the island of Ireland and the security issue presented could only be resolved by reducing the output of one or a small group of price taking generation units in tie break then that reduction is deemed a constraint and logged as such*." This definition of constraints is a clear identification that constraints actions are applied to units under a low competition environment where there may be little or no differentiation between the commercial offer data.

Considering the SEMC position on the need to apply bidding principles and the SEMC approved EirGrid definition of constraints, it would appear that any redispatch action on a non-priority dispatch unit is non-market based as per Article 13(3)(c) where it states "*Non-market-based redispatching of generation, energy storage and demand response may only be used where:..(c) the number of available power generating,* *energy storage or demand response facilities is too low to ensure effective competition in the area where suitable facilities for the provision of the service are located*;"

Following further review of the Clean Energy Package (CEP) Article 13 and the SEMC decision on the distinction between constraints and curtailment (SEM-13-011), it is ESB GT's view that the redispatching due to constraints is non-market based.

One of the many consequences of market based redispatch for constraints on future non-priority dispatch renewable units is that this decision effectively means the network development strategic approach[2] is now Generation-Led (RA and network driven) by default and not as an outcome of the current ongoing consultation process. ESB GT is not in favour of the Generation Led Approach to connect new renewable capacity. Developers select new renewable capacity sites based on high wind speeds and high solar irradiance to maximise the renewable energy output and deliver the best value for the consumer. Connecting new renewable capacity according to the Generation Led Approach will result in new capacity being connected at locations that may have lower wind speeds and lower solar irradiance than is currently the case. The effect of connecting at sub-optimal sites will result in the need to develop more renewable capacity to make up for the reduced output from the selection of sub-optimal sites. This in turn will add unnecessary cost to support schemes for new renewable capacity and only adding to overall support costs borne by the consumer. Minimising grid development, which is a key feature of this approach, will be important to achieving 2030 targets, but must not be the main diver in achieving the target if the real focus is only minimising economic costs being incurred in a timely fashion.

Once renewable generation is fully active in the market all energy balancing actions taken against its submitted PN by the TSO should be deemed market based. The existence of a network constraint would led to any redispatch being non-market based. By contrast all actions taken against priority dispatch generation who do not submit COD are deemed non-market based.

3.2 Bids and Offers (BCOP/BMPCOP)

ESB GT has a number of concerns with the direction of the SEMC minded to position when considering BMPCOP for compliance with CEP Article 13. Simply put the application of BCOP was originally designed to ensure assets required for constraints only received their SRMC cost when constrained on, as the SEMC believed this would prevent any party knowingly exploiting a constraint. This too is changing given the growing number of decentralised investments that are currently occurring. However, the introduction of ISEM also saw the bidding code of practice applied to the decremental price /quantity pairs. It is questionable whether there needs to be any bidding principles applied to the decremental price/quantity pairs. For most Transmission Constraint Groups there are a large number of units that could be selected to decrease output to solve the constraint. However, for internal network congestion constraints the TSOs are most likely limited to a small select number of units behind the physical network congestion point. The BMPCOP was not sufficiently consulted upon to include renewable units and therefore the SEMC's current view of the BMPCOP must be reconsidered. Until such time, the BCOP, as currently active in SEM, includes the ability to at least reflect opportunity costs and may be sufficient for achieving compliance with CEP Article 13. If the SEMC are of the view to move to BMPCOP then changes are required to reflect the opportunity cost that should be provided to non-priority dispatch renewable units as under CEP Article 13.

A fundamental issue creeping through the consultation is the use of COD for scheduling and dispatching. ESB GT's understanding from the Balancing Market Principles Statement (BMPS) is that any actions taken outside of the LTS, which would include constraints, are scheduled off the simple offers not the BCOP complex offers. To be clear, the RTD and RTC uses the simple offers to schedule units and it would appear

[2] EirGrid and SONI Report "Shaping our electricity future" 2021

that these offers are used for the redispatch and dispatching of wind units (outside of unit commitment decisions which will most likely not apply to the redispatching that is being reviewed for compliance with Article 13). The use of BCOP for SEM was primarily on the basis of bringing a unit on which is done via the LTC (which uses the BCOP complex offers only) or any action taken before gate closure. The SEMC's view in SEM-21-027 to compensate non-PD units up to the DAM price would not appear to be in line with the actual scheduling and dispatching algorithms. In the balancing market pricing methodology, all actions are deemed to be energy first and then non-energy through the flagging and tagging process. The SEMC position that "*to compensate non-PD units up to the DAM price is based on a number of considerations;…3. Based on non-discrimination between different units that may be subject to different support schemes.* ***Dispatch and redispatch decisions should arguably be based on marginal operating costs and system security considerations*** *and not different compensation levels associated with foregone support under different support mechanisms*" is flawed and needs to be reconsidered. Equal treatment should be applied to all generating units within the TSOs scheduling and dispatching tools without reference to their support or in general bid prices and therefore it is not clear how it is possible to treat non-PD units differently by scheduling, dispatching and redispatching such units off a different set of commercial offer data i.e. complex for actions taken after the gate closure.

The intention of the BCOP/BMPCOP is to ensure no unit is able to abuse its position as a monopoly at times of locational constraints when needed to generate. In Offers in the ISEM Balancing Market Consultation Paper (SEM-16-059), the SEMC identified that the rationale behind the proposal to prohibit foregone revenue "*was that costs items included in SRMC should be costs incurred as a direct result of the electricity generation process and not based on probabilities and theoretical costs.*" Under constraint redispatch situations the renewable unit should be entitled to recover the revenue it would have received if it was not re-dispatched. Financial compensation set out under Article 13(7) is analogous to that provided for under the bidding code of practice and is effectively a restatement and reaffirmation of the opportunity cost principle for units deemed to be serving a system constraint.

The current experiences from the market have highlighted the need to reconsider the transition from BCOP to BMPCOP. There is no need for a BCOP, however, if the SEMC insist in applying a bidding principles than participants should be allowed to reflect the true opportunity cost of the TSO action in decremental prices. The SEMC have the ability to satisfactorily and quickly implement the CEP Article 13 by identifying all redispatch actions as non-market based and allow participants to reflect their opportunity cost in both their simple and complex COD through the continued application of BCOP where regulatory limits are to be retained. Such an approach would ensure equal treatment for all non-priority dispatch units (renewables and thermal).

3.3 Unjustifiably High Compensation

ESB GT strongly disagrees with the position that providing the compensation as set out under 13.7 (b) to firm priority dispatched generation that is redispatched results in excessively highly compensation. The provision under 13(7)(b) provides for the unit's opportunity cost and is in line with the market design for all other categories of firm generation when subjected to non-energy actions by the TSO. Financial compensation set out under Article 13(7) is analogous to that provided for under the bidding code of practice and is effectively a restatement and reaffirmation of the opportunity cost principle for units deemed to be serving a network system constraint.

ESB GT does not see how compensation to the financial support mechanism level, as provided for in Article 13(7)b can be viewed as unjustifiably high for non-priority dispatch units that are subject to non-market based redispatch. The SEMC appear to have taken a position on not allowing compensation to the full support level for redispatch on Priority Dispatch units due to its view that it is unjustifiably high and applied it carte blanche to non-priority dispatch but then subsequently propose to allow for different levels of compensation for non-priority dispatch units under curtailment redispatch to reflect the value as if it had priority dispatch status. It is not clear why the SEMC's position on preventing compensation to the financial support mechanism level for priority dispatch units (in order to not improve the financial situation of units where investments have already been made) should be applied to non-priority dispatch units.

Considering the DAM is the first exclusive route to market , the value the non-Priority Dispatch units receive from a DAM schedule is not just the DAM revenues but that of the full support mechanism. Any curtailment / constraints on an availability that isn't traded in the ex-ante markets should not receive any compensation as it could be argued that such TSO actions are not market based as these actions were never in the market in the first place and shouldn't be compensate to the DAM or level of support. That said if the non-priority dispatch unit has an ex-ante trade than the compensation to the full level of financial support is justified.

ESB GT questions the consumer benefit derived by prohibiting the recovery of the full support value in redispatching and the potential implications such a decision could have on future RESS strike prices. The increased risk by the proposed decision may be reflected in the RESS strike price meaning the consumer takes on an increased risk profile.

3.4 Incentive to give up PD status

In the consultation paper, the SEMC have proposed to "*provide financial compensation for non-market based redispatch associated with curtailment based on a different compensation regime for priority dispatch and non-priority dispatch units. This is based on the value of priority dispatch and to provide a potential incentive for units to voluntarily give up priority dispatch, which may in turn reduce levels of curtailment where units are not run to their availability.*" It is unclear if such an incentive will outturn from the proposal as it was identified in the consultation paper that the non-priority dispatch units will be constrained prior to any curtailment[3] thus significantly increasing that possibility of receiving no difference in compensation as the MW curtailed would be hidden because they would be defined as constrained MW.

Under the current proposal ESB GT does not believe the value of priority dispatch has been reflected and that there is a potential incentive for units to voluntarily give up priority dispatch. A truer reflection of the value of priority dispatch may be non-priority dispatch units being allowed to reflect the value of their support in the simple and complex COD. If non priority dispatch units are compensated to the full level of support mechanism then priority dispatch units may be incentivised to give up priority dispatch status while at the same time accomplishing the decarbonisation agenda. This would move the greater number of players into the competitive DAM resulting in far greater market outcomes that would result in the efficiency that the RAs identified.

3.5 SNSP limit in the DAM

ESB GT does not agree with the introduction of a SNSP limit or any other system constraint in the ex-ante markets. As set out in the CEP "*core market principles should set out that electricity prices are to be determined through demand and supply. Those prices should indicate when electricity is needed, thereby providing market-based incentives for investments into flexibility sources such as flexible generation,*

[3] "*It is expected that many non-priority dispatch units will be constrained before pro-rata curtailment is applied in order to continue to facilitate priority dispatch generation and the TSOs' rules for dealing with constraint decisions in the first instance. It is also acknowledged that there is often an interaction between constraints and curtailment, which constantly vary in real time. The importance of distinguishing between constraints and curtailment to the greatest extent possible was recognised in SEM-13-010 given their different treatment for market payments. This distinction will become even more important based on the proposals for treatment of redispatch for constraints and curtailment outlined in this paper and energy actions applied to new renewable units in the market.*"

interconnection, demand response or energy storage". The introduction of a SNSP limit or system constraints in the ex-ante markets is a backwards step from liberalised markets and ISEM.

ESB GT agrees with the RAs that the introduction of such a cap could be discriminatory to certain types of generation to which the cap would be applied and may not be fully compliant with the requirements of Article 13(7) to provide compensation for non-market based redispatch.

Finally, the introduction of such a cap would distort the investment signals not just for flexible sources but also the investment signal to improve the network. This constraint in the ex-ante markets coupled with the application of Locational Capacity Constraint Areas (LCCA) in the CRM will distort the genuine signal to incentivise the TSOs to complete grid investment to resolve transmission constraints, as envisaged in the State Aid Decision. If both of these "constraints" are applied it is questionable where, if any, signal for network investment can come from.

3.6 Future limit on compensation

It is unclear what signal the RAs are trying to send to the market with the suggestion that a limit on compensation under Article 13(7) could be included in future to account for the higher targets of SNSP and levels of non-synchronous generation which can be physically accommodated on the system. This proposal creates significant regulatory uncertainty for investors looking to participate in the upcoming RESS auctions. Transparency and certainty is required on these issues in conjunction with this decision. To delay only increases the risk profile exposed to RESS 2 investors and introduces a potential unnecessary cost to the consumer.

ESB GT does not think it is prudent to change the compensation levels due to the SNSP level on the system. This proposed position is sending mixed signals to the market and could cause a similar boom and bust approach as seen in the CRM. The approach of placing curtailment and constraint risk on generators and distorting the network investment signal may lead to NI and ROI missing our renewable and decarbonisation targets in the future.

3.7 Payment for Non-Market Based Redispatch since January 2020

In the consultation paper two option have been proposed to implement an ex-post system of payment for non-market based redispatch associated with curtailment from January 2020;

- Option 1: TSOs to compile information
- Option 2: Individual generators to submit information and TSOs assess information

Considering these options need to be reassessed in light of constraints being non-market based as well, ESB GT believes Option 1 may be the more appropriate approach to identifying and compensating for non-market based redispatch (curtailment and constraints) since January 2020.

3.8 Firmness

Considering the implications that firm status can have on a renewable project and the level of compensation it is exposed to, clarity is required on the firm access policy as soon as possible. Firmness should not be dependent on the timing of a network rollout that has been paid for and is needed to achieve our emissions targets as a country. As an industry there are responsibilities on the generator investor community but also the regulator to ensure that the price controls are sufficiently financed to deliver the firmness that these units are promised. This temporary assignation to non-firm should not be used in a manner that limits the incomes of those parties who have fairly participated in the auctions.

3.9 Decremental actions applied to priority dispatch units

In the consultation paper the SEMC asked the following question;

Where priority dispatch units are dispatched down in order to manage the demand-supply balance, clarity is required on whether this represents;

(i) a form of balancing energy, to resolve the balance of supply and demand, or;

(ii) redispatch, to either respect system and operational constraints (either as curtailment or a constraint) or to respect the constraint of the priority dispatch hierarchy policy.

ESB GT assumes this is in relation to MOD_10_19[4] and the following response should be read in light of the modification. Via the consultation and this decision paper, the SEMC with industry have come to the view that redispatch can be identified as constraints and curtailment and dispatch is energy balancing. As per the modifications committee, ESB GT believes that even though Priority Dispatch isn't a physical constraint it can be viewed as a regulatory constraint placed upon the TSOs and is thus a non-market based action.

As a result, a dispatch down order to manage the demand-supply balance on a priority dispatch unit could be viewed as a form of non-market based dispatch as it is an energy balancing action. Such an action is not defined in the CEP or EBGL and, as per the T&SC priority B.4, is subject to the outstanding SEMC decision. Therefore, ESB GT is of the view that any action that is non-market based should not be not be price setting.

4. COMMENTS ON PROPOSED DECISION PAPER SEM-21-027

In this section ESB GT has highlighted some of its views on this consultation and the implementation of CEP.

4.1 Treatment of flagging for internal congestion

Alongside the principles discussed above on why a redispatch action for a constraint on a non-priority dispatch renewable unit is non-market based, there is also the issue of equal and consistent treatment of such actions in the balancing market. In the current EBGL compliance consultation paper (SEM-21-017), under the treatment of congestion and price setting issue, it is identified that the System Operator Flagging step does not consider flagging in regard to internal congestion and that the NIV tagging step would address the internal congestion tagging. This current approach is considered to be compliant for EBGL and no change is being proposed. Reviewing it from a whole market point of view it is a reasonable approach to take and should work for constraints due to TCGs however, ESB GT is unsure of the consequences it may have when considering the compensation allowed for under CEP Article 13. For example, it is possible for two non-priority dispatch renewables to be constrained due to the same network issue but when it comes to the flagging and tagging methodology only one is flagged and compensated as per its complex COD whereas the other unit is compensated as per its simple COD. Considering both units will be scheduled and dispatched as per its simple COD, it would not appear non-discriminatory or consistent to not allow complex COD to reflect the same opportunity cost that the simple COD will.

Additionally, will the T&SC account for different flags on a number of actions taken by the TSO on the wind unit? For example, what will be the nature of the classification if the first dec quantity was for constraints and the second dec was for curtailment. Will the wind farm be compensated accordingly or will it be similar to today's mechanism where the last action determines the status of all actions taken on the unit? If so, this

[4] Mod_10_19 Removal of negative QBOAs related to dispatch priority units from the imbalance price

could cause issues for compensation and the difference in treatment of compensation for curtailment and constraints when multiple actions are taken on a non-priority dispatch renewable units. If this is to be applied to wind units it would need to be applied to all units participating in the BM to ensure there is no discrimination and unequal treatment.

It is ESB GT's view that redispatching on non-priority dispatch renewable units is non-market based and that the above potential issues with flagging and tagging are not a problem as any decremental action taken on a wind unit (non-priority and priority dispatch) should be automatically flagged out and not allowed to set the price and subsequently settled on its BCOP complex offer data.

4.2 Interim until systems implemented

ESB GT believes the ending of priority dispatch requires the facilitation of full participation in the market by renewable generation. The TSOs and Market Operator should, under the direction of the SEMC, begin the programme of work to enable this participation immediately.

While ESB GT appreciates the complexity of the systems and processes in question and the resource and time constraints faced by the TSOs this does not belie the fact that the Regulation is in force. As such once the principles of the implementation are decided there will be an urgent need to progress interim measure to ensure that market participants are not commercial disadvantage due to a delayed implementation.

The interim measures will be urgently required to protect market participants who are commercially disadvantaged due to the delayed implementation of the Regulation.

In terms of moving forward, the severity of system changes may be reduced if redispatching non-priority dispatch units is view as non-market based and compensated to the full level of support.