Single Electricity Market

(SEM)

Consultation on Dispatch, Redispatch and Compensation Pursuant to Regulation (EU) 2019/943

SEM-21-026

23 April 2021

EXECUTIVE SUMMARY

This further Consultation Paper provides the Regulatory Authorities' 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, focusing on the definitions of dispatch, redispatch and non-market based redispatch in the SEM and arrangements for compensation under Article 13(7).

While it was previously indicated to stakeholders that these issues would be presented as part of a Proposed Decision Paper, a further Consultation is now being published for stakeholder feedback. The scope of this Consultation includes the following issues consulted on as part of SEM-20-028, along with additional considerations related to this area;

1. The interpretation of dispatch and redispatch in relation to the Single Electricity Market.
2. The nature of decremental actions taken on priority dispatch units.
3. The interpretation of actions which are considered market based and non-market based redispatch under the current market rules, noting the potential for future changes which may have an impact on this.
4. A proposal for the determination of the appropriate level of compensation for non-market based redispatching and how this can be implemented.
5. Options for implementation of ex-post compensation arrangements from 1 January 2020.

Each proposal outlined in this further Consultation Paper is summarised below;

Dispatch and Redispatch

The Regulatory Authorities' minded to position is that in the SEM, dispatch relates to the scheduling and dispatch of units to meet the energy requirements of the market, noting the complexity of identifying dispatch and redispatch separately in the central dispatch system with an integrated scheduling process, which is carried out through the identification of energy and non-energy actions as part of the flagging and tagging process. Energy balancing in the SEM aligns with the definition under the Electricity Balancing Guideline as '*energy used by TSOs to perform balancing and provided by a balancing service provider'*. Taken together, dispatch and energy balancing are aligned to the existing concept of 'energy actions' in the SEM.

Redispatch in the SEM relates to deviations from the market schedule for generation for both local network and broader system reasons, including TSO-instructed changes in generation due to localised network issues (constraints) and reduction in non-synchronous generation due to other system-wide reasons such as levels of System Non-Synchronous Penetration (curtailment). Many respondents to the Consultation noted that the concept of redispatch aligns to the concept of the activation of non-energy actions in the SEM. While the Regulatory Authorities broadly agree with this interpretation, the distinction between energy and non-energy actions is not made in the scheduling and dispatch process but as part of the ex-post imbalance pricing process.

Decremental actions applied to priority dispatch units

The classification of dispatch and redispatch in the SEM also needs to be clarified in relation to priority dispatch units. In the SEM, the output of priority dispatch units is maximised as far as technically feasible based on the hierarchy of units defined in SEM-11-062. This is based on an 'absolute' interpretation of priority dispatch whereby economic factors are only taken account of in exceptional situations. This is given effect to through the application of a range of TSO-generated negative decremental prices to units classified as priority dispatch.

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.

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

Market and non-market based redispatch

This further Consultation also outlines the Regulatory Authorities' proposals in relation to the classification of non-market based redispatch in the SEM, which is relevant to the application of Article 13(7).

The Regulatory Authorities are of the view that curtailment in the SEM is currently a form of non-market based redispatch, as it is applied to all non-synchronous units (regardless of priority dispatch status) and is not based on any merit order or the bids and offers of units.

In the Regulatory Authorities' view, constraints as applied to all non-priority dispatch units are a form of market based redispatch. Taking on board the arguments of the majority of Consultation respondents, the Regulatory Authorities propose that constraints as applied to all priority dispatch units are a form of non-market based redispatch.

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

Compensation Under Article 13(7)

In order to comply with the requirements in Article 13(7) and in the context of the considerations within the preceding sections of this paper, the Regulatory Authorities propose to provide financial compensation for non-market based redispatch associated with curtailment. This proposal is based on providing different levels of compensation for priority dispatch and non-priority dispatch units 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.

All units that are currently eligible for priority dispatch would receive compensation for non-market based redispatch (in relation to curtailment), where firm, up to the level of any additional operating costs caused by redispatching pursuant to Article 13(7) (a). Based on the understanding that the marginal cost of non-synchronous units subject to curtailment is minimal and the Curtailment Price would continue to apply, these units would also have the opportunity to benefit from the same treatment as new units outlined below if they chose to surrender their priority dispatch rights.

All new units, which are no longer eligible for priority dispatch, based on the criteria outlined in SEM-20-072, would be subject to compensation under Article 13(7), where firm and subject to non-market based redispatch (in relation to curtailment) up to the level of the DAM price at the time they are curtailed. All units would have the opportunity to avail of compensation up to the level of the DAM price in exchange for surrendering their priority dispatch rights. This is linked to the implementation of market changes to facilitate non-priority dispatch renewables set out in SEM-21-027.

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

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1. Introduction

1.1 Clean Energy Package Background

The Clean Energy for all Europeans package (CEP) consists of eight legislative acts which were adopted by the European Parliament and European Council in 2018 and 2019 following Commission proposals in November 2016. This involves a comprehensive update of the EU's energy policy framework aimed at enabling the transition to cleaner energy and facilitating a reduction in greenhouse gas emission levels of 40% by 2030 compared to 1990. The revised Regulation on the internal market for electricity (EU) 2019/943[1] under the CEP seeks to amend aspects of wholesale electricity markets in Europe, enhance integration and progress the transition to renewable energy. Having entered into force in July 2019, the majority of the Articles in the Regulation apply from January 2020.

A high-level review was conducted by the Regulatory Authorities (RAs) in the second half of 2019 to identify the areas of the Regulation which may require action by the SEM Committee with respect to the all-island SEM. The RAs identified a number of areas for action by the SEM Committee in 2020, along with coordination with relevant Government Departments in Ireland and Northern Ireland, in order to progress implementation of the Regulation. Based on this review, a Roadmap for progressing these six areas in 2020 was outlined by the SEM Committee in an Information Paper published in December 2019[2]. An update to this Roadmap was published in December 2020[3].

Two of the areas identified in the Information Paper relate to Article 12 '*Dispatching of generation and demand response*' and Article 13 '*Redispatching*'. Options for the implementation of these Articles in the SEM were consulted on in SEM-20-028. This Consultation closed on 22 June 2020 and considered a range of issues including the definition of dispatch and redispatch in the SEM, changes to eligibility for priority dispatch under the Regulation and compensation for non-market based redispatch.

Following the Consultation on implementation of Articles 12 and 13 of the Regulation, an Information Note, SEM-20-052 was published which outlined the areas of work that the RAs would be progressing following the initial Consultation. One of the workstreams identified in the Information Note relates to the definition of dispatch and redispatch in the SEM, the

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[1] Regulation (EU) 2019/943 on the internal market for electricity.
[2] SEM-19-073 Roadmap to Clean Energy Package Implementation
[3] SEM-20-089 Updated Roadmap to Clean Energy Package Implementation

classification of non-market based redispatch and implementation of compensation pursuant to Article 13(7). Following further analysis and review of responses received it has been decided to present the RAs' minded to positions in a number of areas for further feedback, particularly in the area of financial compensation for non-market based redispatch as part of this further Consultation Paper. This paper is also published with a Proposed Decision on the treatment of new renewable units in the SEM, SEM-21-027.

1.2 Purpose of this further Consultation Paper

This further Consultation Paper provides the RAs' minded to positions in relation to specific areas of the Consultation Paper, SEM-20-028, related to the implementation of Articles 12 and 13 of the Electricity Regulation.

These areas considered in this paper include;

1. The interpretation of dispatch and redispatch in relation to the Single Electricity Market.
2. The nature of decremental actions taken on priority dispatch units.
3. The interpretation of actions which are considered market based and non-market based redispatch under the current market rules, noting the potential for future changes which may have an impact on this.
4. A proposal for the determination of the appropriate level of compensation for non-market based redispatching and how this can be implemented.
5. Options for the application of this requirement from 1 January 2020.

The RAs' proposals in each of these areas are outlined for further comment from interested stakeholders in Section 2 of this paper. In coming to the proposals outlined in this paper, the RAs have considered the responses received to the initial Consultation proposals along with feedback received through engagement with stakeholders, other National Regulatory Authorities and the European Commission.

Comments are invited on this further Consultation Paper until 02 July 2021 and can be sent to gkelly@cru.ie and Gary.Mccullough@uregni.gov.uk. All non-confidential responses will be published with the SEM Committee's Decision in this area.

2. Feedback Received and further Consultation Proposals

2.1 Definition of Dispatch and Redispatch

Consultation Proposals

SEM-20-028 considered the importance of clearly defining how the terms used in the new Electricity Regulation (Regulation (EU) 2019/943) are interpreted in the SEM context and made proposals on the interpretation of dispatch and redispatch in the SEM.

In relation to dispatch, the RAs proposed that in the SEM this relates to the scheduling and dispatch of units to meet the energy requirements of the market, as part of the scheduling and dispatch process managed by the TSOs and outlined in the Balancing Market Principles Statement. The TSOs must take account of operational security, efficient operation of the SEM and the maximisation of priority dispatch as part of this process.

Redispatching is defined in the Electricity Regulation as *'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'.* It was proposed that redispatching in the SEM relates to the alteration of generation for both local network and broader system reasons, including TSO-instructed change in generation due to localised network issues (constraints) and reduction in non-synchronous generation due to other system-wide reasons such as levels of System Non-Synchronous Penetration (curtailment).

The definition of constraints referenced in the Consultation was *'the dispatch down of generation due to localised network reasons, where only a subset of generators can contribute to alleviating the problem.'*

The definition of curtailment referenced in the Consultation was '*the dispatch down of non-synchronous generation for system wide reasons, where the dispatch down of all such generators would alleviate the problem.'*

These definitions are in line with the difference between constraint and curtailment approved by the SEM Committee in SEM-13-011 and the TSOs' renewable constraint and curtailment reports[4].

Feedback Received

The majority of respondents support the RAs' interpretation of Dispatch and Redispatch in the SEM context. In their response, IWEA and NIREG state that they agree with the scheduling and dispatch process outlined in Figure 3 of the Consultation whereby constraints and curtailment are considered forms of redispatch. Codling Wind Farm Limited EDF Renewables, ElectroRoute Energy Supply Limited, BGE, Bord na Mona, SSE and Cloosh Valley Wind Farm also support this interpretation in their responses.

Coillte broadly agree with the alignment between the SEM terminology of 'energy actions' being considered dispatch and 'non-energy actions' being considered redispatch, however in their response they raise some concerns with the legacy definition of curtailment and the apparent application of priority dispatch to dispatch only. They note that the definition of curtailment under SEM-13-010 implicitly contains an element of energy balancing for priority dispatch renewables when the sum of the available renewable generation exceeds the demand to be served. Currently, all dispatch down in this scenario is treated as curtailment even though some of this dispatch down should be classified as 'energy balancing' within the context of 'dispatch' under the Clean Energy Package. This portion would be settled at its Decremental price, either submitted or deemed to be €0/MWh.

ISEA agrees that dispatch in the Regulation maps to the concept of energy balancing in the SEM and Redispatch in the Regulation maps to the concept of non-energy actions in the SEM but notes that the detail of this is important. In their view, downward redispatching of renewables in the SEM to meet a System Non-Synchronous Penetration (SNSP) limit is defined as curtailment through both the SEM-13-010 definition and the nature of the control instruction from the TSO. However, if the total amount of available renewable energy exceeded demand in a particular 5-minute period, some of those downward redispatch actions may be classified as energy balancing. ISEA note that a clear definition is required as to what is meant by energy balancing.

CEWEP and Indaver share the view that energy actions are representative of dispatch and non-energy actions are redispatch. CEWEP note however that curtailment is considered solely within the context of non-synchronous generation in the Consultation. The majority of dispatch

[4] http://www.eirgridgroup.com/site-files/library/EirGrid/Annual-Renewable-Constraint-and-Curtailment-Report-2019-V1.2.pdf

down of CEWEP facilities occurs during periods of non-synchronous curtailment where there is a requirement to keep a minimum number of must run generators synchronised to the Grid for system stability. CEWEP facilities are turned down before wind due to the application of the SEM-11-062 hierarchy.

Aughinish are of the view that Section 1.2 of the Consultation Paper is not clear enough to fully agree with the RAs interpretation of dispatch and redispatch and are concerned with how this may be applied to the Balancing Market Principles Statement.

ESB GT highlight in their response that dispatching and redispatching of units occurs within a single scheduling process undertaken by the TSOs. On this basis it would be challenging for the TSOs to determine whether a given action to deviate a unit from its submitted Physical Notification (PN) was undertaken as a dispatch, or in SEM terms, an energy only action or as redispatch or non-energy action. To address this under the current SEM arrangements a ruleset has been developed as a subsidiary document to the Trading and Settlement Code, termed the Methodology for System Operator and Non-Marginal Flagging, which sets out a ruleset for the ex-post determination of an action's status as energy only or non-energy. In ESB GT's view all actions by the TSOs against the submitted PNs of non-priority dispatch renewable generation are market based with the categorisation of dispatch and redispatch being determined through an ex-post ruleset captured in an updated version of the Methodology for System Operator and Non-Marginal Flagging.

In their response, ESBN note that they have had a limited role with regard to dispatch and redispatch to date apart from initial steps regarding reactive power management, facilitation of Demand Side Units (DSUs) and non-secured generation connections. This may change however as the DSO takes on a more active role in this area and in their response ESBN highlight their concern that the implementation of Articles 12 and 13 should not limit the DSO's ability to introduce market-based solutions to maximise renewable and demand side participation in an open and secure market. ESBN request in their response that the provisions for implementation allow for the following developments;

1. Active management or dispatch of renewable generation and demand at a local and regional level.
2. Active management of constraints and potentially curtailment at a local and regional level.

ESBN also note that there is a need to clarify the RAs' intended treatment of forced and planned outages and instruction sets applying to individual Demand Sites which use high efficiency cogeneration as part of their DSU activities.

In their response, NIE Networks state that the RAs have presented an interpretation that the only forms of redispatch within the SEM are curtailment (system wide issues) and constraint (local issues). On this basis, NIE Networks agrees that in the current SEM the TSOs are responsible for dispatch (central dispatch market model) and redispatch.

NIE Networks note that as the scheduling and dispatch process does not produce a physically secure schedule with regards to the distribution network, NIE Networks may issue a request to SONI to dispatch down specific generator(s). This request will not take account the cost of diverging from PNs, as the DNO has no visibility of that information. NIE Networks also currently issues Instruction Sets to DSUs in order to facilitate their operation in a way that does not adversely impact the safety and operation of the distribution network. These Instruction Sets inform the availability of the DSUs in the SEM.

EirGrid and SONI consider that Articles 12 and 13 of the Regulation are written in the context of a predominantly self-dispatched internal energy market across the EU. In the context of the SEM, however, the application of Central Dispatch and integrated scheduling need further consideration, with respect to the concepts of dispatch and redispatch in the Regulation. In a central-dispatch-based system, the TSO determines each unit's dispatch instruction, which is informed by PNs, but the TSO is not obligated to follow this.

Regulatory Authority Response and further Consultation Proposals

Dispatch and Balancing Energy

Following assessment of the feedback received, the RAs are of the view that in the SEM, dispatch relates to the scheduling and dispatch of units to meet the energy requirements of the market. The RAs recognise the complexity of identifying dispatch and redispatch separately in the central dispatch system with an integrated scheduling process as highlighted in EirGrid and SONI's response. The TSOs must also take account of operational security, efficient operation of the SEM and the maximisation of priority dispatch as part of this process.

Many respondents noted that the concept of dispatch aligns to the concept of energy actions taken to resolve imbalances between the energy supply-demand balance. As highlighted by a number of respondents, the TSOs do not distinguish between energy and non-energy actions as part of the scheduling and dispatch process as each action can have an energy and non-energy component, with the distinction being made on an ex-post basis through flagging and tagging as set out in the 'Methodology for System Operator and Non-Marginal Flagging'. This is an iterative process to determine which actions were primarily for energy purposes and which actions were primarily for non-energy purposes.

The integrated scheduling process implicitly includes dispatch, redispatch and balancing energy. ‘Balancing energy’ here is aligned to the definition in the Electricity Balancing Guideline as ‘*energy used by the TSOs to perform balancing and provided by a balancing service provider*’. A complexity to this interpretation that has been noted by a number of respondents including Coillte and ISEA relates to how this interpretation applies to priority dispatch, for example in a scenario whereby the sum of available priority dispatch renewable generation exceeds the demand to be served in a particular 5-minute period. Currently, wind and solar units with priority dispatch are only subject to constraints and curtailment and systems cannot dispatch these units for energy balancing purposes. This issue is considered further in a separate part of Section 2.1 below and updates which may be required to SEM-13-011 in terms of the distinction between constraints, curtailment and energy balancing, particularly in the context of the changes required to facilitate new renewable units in the market, are also discussed in the SEM Committee’s Proposed Decision Paper on the treatment of new renewable units in the SEM (SEM-21-027), which has been published along with this paper.

Regulatory Authority Proposal:

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

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

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

Redispatch

The TSOs may need to dispatch a unit away from its PN for other system reasons including management of transmission constraints. The RAs are of the view that redispatch in the SEM relates to deviations from the market schedule for generation for both local network and broader system reasons, including TSO-instructed reduction in generation due to localised network issues (constraints) and reduction in non-synchronous generation due to other system-wide reasons such as levels of System Non-Synchronous Penetration (curtailment).

Many respondents to the Consultation noted that the concept of redispatch aligns to the concept of non-energy actions in the SEM. While the RAs broadly agree with this interpretation, the distinction between energy and non-energy actions is not made in the scheduling and dispatch process but as part of the ex-post imbalance pricing process.

In their response, ESBN noted their concern that any SEM Committee Decision in this area should not limit the DSO's ability to introduce market-based solutions to maximise renewable and demand side participation, including active management or dispatch of renewable generation and demand at a local and regional level and active management of constraints and curtailment at a local and regional level. NIE Networks also noted their concern that such an interpretation should not hinder future market developments. The RAs acknowledge that the proposals in SEM-20-028 and in this further Consultation Paper only account for the current SEM arrangements and are not intended to preclude any future market developments including new forms of dispatch and redispatch at the distribution level.

On the issue raised concerning instruction sets applying to Demand Side Units, DSUs' PNs, forecast availability and declared availability prior to Balancing Market gate closure and in real-time operation reflect these DSO/DNO Instruction Sets. This affects the dispatch quantity for a DSU in order to manage congestion at a distribution level and the RAs are of the view that where any changes are introduced at a distribution level to provide market-based solutions for congestion management, this issue will need to be considered further. The Balancing Market Principles Statement notes that where constraints arise on distribution network connected units which impact on the TSOs' ability to dispatch or control such units, the constraint is reflected in the scheduling and dispatch process. Where a distribution connected generator, participating in the SEM, is subject to a TSO constraint the RAs' understanding is that there is no distinction between the treatment of such units in terms of bid offer acceptance or balancing market settlement.

As more generation connects at the distribution level, the management of constraints which limit access to the energy market will need to be addressed. Feedback is invited from Demand

Side Units and System Operators on this point in particular as part of this Consultation Paper and how it may best be managed in terms of Article 13 of the Regulation.

Regulatory Authority Proposal:

- Redispatch in the SEM relates to deviations from the market schedule for generation for both local network and broader system reasons, including TSO-instructed reduction in generation due to localised network issues (constraints) and reduction in non-synchronous generation due to other system-wide reasons such as levels of System Non-Synchronous Penetration (curtailment).
- The Regulatory Authorities acknowledge that future market developments may include new forms of dispatch and redispatch at the distribution level.

Dispatch and Redispatch Applied to Priority Dispatch Units

The Electricity Regulation recognises that in a central dispatch model, priority dispatch refers to the dispatch of generators based on criteria which are different to the economic merit order of bids for both dispatch (scheduling and dispatch of units to meet the energy requirements of the market) and constraints (or redispatch). This is distinct from a self-dispatch model where priority dispatch only considers dispatch of generators. The distinction between dispatch and redispatch, or energy and non-energy actions, applied to priority dispatch units is important in the context of existing SEM Committee Decisions.

In the SEM, the output of priority dispatch units is maximised as far as technically feasible based on the hierarchy of units defined in SEM-11-062. This is based on an ‘absolute’ interpretation of priority dispatch whereby economic factors are only taken account of in exceptional situations. This is given effect to through the application of a range of TSO-generated negative decremental prices to units classified as priority dispatch.

Where priority dispatch units are dispatched down in order to manage the demand-supply balance, clarity is required on whether this represents a form of balancing energy, to resolve the balance of supply and demand, or of redispatch, to either respect system and operational constraints (either as curtailment or a constraint) or to respect the constraint of the priority dispatch hierarchy. This issue is related to the nature of implementation of Absolute Priority Dispatch in the SEM, where economic factors are not taken into account in relation to such units and the broader constraints on the TSOs in scheduling the system, not only those related to system security but due to statutory requirements and priority dispatch. Where all available non-priority dispatch units have already been dispatched down (and are generally nonmarginally flagged at their Lower Operating Limit), dispatchable units with priority dispatch are dispatched down in accordance with the hierarchy order to balance supply and demand.

If generator's Final Physical Notifications (FPNs) do not balance against the forecast demand in a particular period, the TSO dispatches bids or offers to either increase or decrease generation or demand to restore the energy balance. The SEM Committee's Building Blocks Decision Paper (SEM-15-064) set out the framework for the treatment of priority dispatch under the revised market arrangements, noting that priority dispatch generation should not be able to set the imbalance price. Specifically, the paper noted that the decremental bid offer price for zero marginal cost priority dispatch participants should be set to zero, while the decremental price for priority dispatch generation with non-zero production costs should be consistent with the current SEM and should be the avoided fuel cost only. This paper set out the SEM Committee's Decision that the decremental price from priority dispatch generators should be used for settlement purposes only.

SEM-15-064 did not make a distinction between such units for the purpose of pricing and settlement for energy vs non-energy actions. The RAs are of the view that any such decremental actions taken on priority dispatch units should not be price setting but acknowledges the complexity of the situation regarding energy actions and priority dispatch units. As discussed in earlier sections of this paper, all TSO actions in the scheduling and dispatch process have energy and non-energy impacts, and a process is required to determine for pricing and settlement purposes the extent to which an action is primarily taken for energy or non-energy purposes.

Analysis conducted by the RAs and SEMO shows that certain decremental actions taken on priority dispatch units are not currently System Operator flagged or Net Imbalance Volume tagged (i.e. the result of the flagging and tagging process is that such actions are not flagged and therefore can set the price in some circumstances). However, these actions are not only taken to balance the system but also on the basis of policy decisions to maximise output from priority dispatch. Such actions, as they are not flagged or tagged, present a complexity to the interpretation of such actions as forms or dispatch or redispatch in the SEM. This distinction is important in terms of how such actions feed into the Imbalance Price and in relation to Article 13(2), which states that;

'Balancing energy bids used for redispatching shall not set the balancing energy price.'

A Modification[5] raised to the Trading and Settlement Code in 2019 and subject to recent Modifications Committee discussions, attempted to align the operation of the SEM with this earlier SEMC Decision by ensuring such actions on dispatchable priority dispatch units do not set the balancing market price, through the removal of the application of Bid Offer Acceptance Prices related to decremental actions on dispatchable priority dispatch units from Imbalance Pricing. The Modification does this through replacement of the Decremental Price Quantity Pairs of such units with zero for Imbalance Pricing calculations (but not for settlement).

This Modification has not yet been implemented and in October 2020, the SEM Committee decided to defer implementation of this Modification until a decision in relation to dispatch and redispatch in the SEM had been completed, along with a related Consultation on the implementation of the Electricity Balancing Guideline (Regulation (EU) 2017/2195). In February 2021, the SEM Committee also published an Information Note stating that a further Consultation would be progressed on Articles 3, 6 and 10 of the Electricity Regulation, which relate to principles of the operation of electricity markets and price formation. It was noted that this Modification would be deferred until all three Consultations are complete. In the context of this further Consultation, the RAs are seeking feedback on the nature of decremental actions applied to priority dispatch units as a mixture of both energy and non-energy actions or as primarily non-energy actions. This also relates to the issue highlighted previously in this paper regarding the distinction between constraints, curtailment and energy balancing for priority dispatch wind and solar units.

One option following the conclusion of this Consultation and Decision process, along with the associated Consultations referred to above, is to implement this Modification to the market systems, recognising that such actions applied to priority dispatch units do not fit neatly into the concepts of either dispatch or redispatch but nonetheless should not feed into the calculation of the Imbalance Price as decremental prices for such units are not used to determine merit for scheduling decisions on an economic basis. Feedback is invited from respondents to this Consultation on this issue.

Another option the RAs are considering in order to be fully compliant with the requirements of the Electricity Regulation and to reflect this in the concept of Absolute Priority Dispatch in the SEM, is for a new type of flag to be introduced to the flagging and tagging process to ensure that the concept of energy vs non-energy actions is reflected appropriately for priority dispatch units. This would be in addition to the existing flags and tags, which operate as part of the cause-based methodology for distinguishing between energy and non-energy actions, which

[5] Modification_10_19, ‘Removal of negative QBOAs related to dispatchable priority dispatch units from the imbalance price’

currently include System Operator flags, Non-marginal flags and Net Imbalance Volume tagging. The RAs are cognisant that this would take a significant amount of time to implement however.

In instances where a decremental action is taken on priority dispatch units the RAs' initial view is that these are both non-energy and non-market based due to the constraint of priority dispatch placed on the TSOs through policy and legislation summarised in the Balancing Market Principles Statement. These are taken in a regulatory approved order without consideration of economic merit as for units in the market. The policy reasons for these actions being taken is not currently reflected in operational or unit constraints which currently feed into the flagging and tagging process. In such instances, priority dispatch units should not be price setting and should be settled on the basis of their complex bids. This would also reflect the position set out in SEM-15-064 that the decremental price for priority dispatch generation should be the avoided fuel cost only.

Regulatory Authority Proposals:

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

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

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

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

2.2 Definition of Non-Market Based Redispatch

Consultation Proposals

Based on the definition of redispatch proposed in SEM-20-028, the RAs took the view that in the case of the application of constraints, in the SEM this is a form of market-based redispatch and is remunerated via the current rules in place through balancing market settlement. This view was based on the fact that TSOs take account of Commercial and Technical Offer Data submitted by Participants to minimise the cost of diverging from PNs when taking actions to manage constraints.

In terms of compensation, there are market rules in place for generators whereby if a unit is firm and is moved from its ex-ante market position in the balancing market for non-energy reasons (i.e. due to constraints), it may be compensated based on its bids and offers. For all generators, excluding wind and solar units which do not submit bids or offers, this compensation is provided through premium and discount component payments. If a unit's Bid Offer Price is greater than the Imbalance Settlement Price, it receives a Premium Component Payment. If its Bid Offer Price is less than the Imbalance Settlement Price, it receives a Discount Component Payment. In this way, if a firm generator is turned down from its ex-ante position, it can retain any inframarginal rent from its ex-ante market revenue.

If a non-firm unit is constrained below their ex-ante market position, any action to turn a unit down in the range above their Firm Access Quantity is considered an imbalance, rather than a redispatch action, as the market position of the unit is not firm above their Firm Access Quantity level. This imbalance is purchased by the generator unit at the Imbalance Settlement Price.

For wind or solar units, currently this policy is implemented by firm units retaining any ex-ante revenue they have earned for the amount they have been constrained below their market position, as such units do not interact with the market systems in the same way as other units in the balancing market through the submission of bids and offers. The treatment of new units is further considered separately in SEM-21-027. This is implemented through having a deemed decremental price of zero for these units for use in settlement, resulting in a Discount Payment equal and opposite to the Imbalance Component Charge the unit would also have, meaning net settlement for the unit of zero for the constraint in the Balancing Market.

In the case of curtailment, this is currently applied on a pro-rata basis to all non-synchronous units (as per the Decision in SEM-13-010) due to system-wide reasons and is not selected based on submitted bids of particular units. The RAs proposed in SEM-20-028 that this represents a form of non-market based redispatching in the SEM.

Under the current market rules, if a unit is firm and is curtailed below their ex-ante market position, then the quantity of curtailment is settled at the Curtailment Price. This is also the case for non-firm units. In effect, units do not retain their ex-ante revenue for the amount they have been curtailed below their market position but are not exposed to the imbalance price. Net settlement in this instance is at a level, which is representative of a units ex-ante market revenue, rather than being settled at the Imbalance Settlement Price.

Feedback Received

The majority of respondents supported the RAs' interpretation of curtailment as a form of non-market based redispatch, but many were strongly of the view that constraints as applied to priority dispatch units should also be considered as non-market based.

In their response, supported by their members, IWEA and NIREG argue that curtailment should be considered non-market redispatch, however they strongly believe that constraints should also be considered as non-market redispatch where units are subject to constraint actions are not chosen with reference to any submitted prices or to the supply/demand balance but solely due to local system limitations. IWEA and NIRIG note that that the existing market systems do not consider Technical Offer Data (TOD) or Commercial Offer Data (COD) from wind or solar generation so it cannot be interpreted that constraint actions for such generation could be considered anything other than non-market based redispatch.

Coillte supports IWEA and NIRIG's position that constraints should be considered non-market based redispatch and note that if priority dispatch generation is treated under a form of market merit order for redispatch this would represent a diminution of the existing priority dispatch rights for such generators. In their view, careful consideration is also needed on whether the BMPCOP's application to all redispatch (aka SRMC complex offers applying to all non-energy actions) is consistent with the requirements of the Regulation. Coillte also propose that constraints should be considered as non-market based redispatch for all renewables.

In their response, ElectroRoute state that they have concerns about the distinction between market and non-market based redispatch. They agree that at present, curtailment in the SEM can be regarded as non-market based redispatch because COD is not considered in the decision to redispatch generators. They note that there are market-based influences on the volume of curtailment redispatch, including interconnector flows which are set by the results of the ex-ante markets and the prices during periods of high wind. ElectroRoute also raise the point that a market-based approach to curtailment may be preferable to allow units to submit bids reflecting their willingness to be curtailed.

ElectroRoute agree that redispatch due to the application of system constraints has an economic merit order if the units involved in the constraint are redispatched solely based on their COD & TOD. However, as soon as a constraint causes redispatch of a unit that does not submit COD or TOD (i.e. non-dispatchable generation), then the decision is not following an economic merit order and cannot be market based.

SSE agree that market-based redispatch needs to take account of the COD and TOD submitted by participants. As no priority dispatch unit is capable of submitting COD or TOD to minimise the cost of diverging from an ex-ante schedule, in SSE's view all redispatch of renewable generation is non-market based.

Cloosh Valley Windfarm note in their response that PNs and COD and TOD from wind units are not considered as part of the market solution, therefore both constraints and curtailment for these units must be non-market redispatch.

In Enerco's view, given that priority dispatch units do not bid into the balancing market it is clear that constraints and curtailment are non-market based redispatch. Enerco also note that there may be a misapprehension that the TSOs use a price of €0/MWh when constraining units in the balancing mechanism. However, this only applies to firm capacity, with the imbalance price being used for non-firm capacity. This is a price deemed by the TSC not a market price submitted by a participant and as a result this cannot be market based redispatch.

Energia is of the view that redispatch should be market-based, open to all and financially compensated. In their view, non-market based redispatching of generation is only permitted where a market-based solution is not available, has been fully exhausted or for reasons of competition related to congestion or otherwise, it is not possible. Energia state in their response that the RAs have erroneously concluded that constraints in SEM are market based and argue that constraints in SEM are non market-based.

Codling Wind Park is of the view that constraints should also be considered non-market based redispatch, as units that are subject to constraint actions are not chosen with reference to any submitted prices or to the supply/demand balance but solely due to local system limitations.

ERG Renewable states that in some cases, curtailment and constraint events happen simultaneously without a clear distinction between the two activities.

In Bord na Mona's view, where generators are constrained due local network constraints, this represents a form of redispatch without regard to market PNs or COD and there is no reasonable basis that this type of redispatch can be classified as market based. Therefore, the constraint of generators for network congestion reasons can only be classified as non-market redispatch.

Greencoat Capital are of the view that the SEM Committee's conclusion that constraint is market-based redispatch is flawed for priority dispatch generators. Priority dispatch generators are not constrained off on the basis of submitted market offers and therefore it cannot be defined as market based redispatch. If constraint of priority dispatch renewables were to be market based, this would also represent a diminution of the value of priority dispatch, which is not contained within the Regulation.

Innogy Renewable Ireland Limited do not agree with the interpretation of constraints as a market based mechanism for controllable but not dispatchable renewable assets, given the lack of COD / TOD and PNs and FPNs currently utilised. In their view when 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.

ESB GT is of the view that all actions taken against priority dispatch generation are non-market based for the purposes of Article 13. All actions taken against a PN submitted by a non-priority renewable generator, as they are determined and settled against a price submitted by that generator, are market-based for the purposes of Article 13.

BGE notes in its response that constraint decisions in SEM are all based on a price, either 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. In BGE's view due to the definition of curtailment, the pro-rata rule and the 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.

In CEWEP's view, either all constraints should be considered non-market based redispatch or constraints should be considered market based for non-priority dispatch plant only. While DWTE agree with the SEM Committee's view that curtailment in the SEM represents non-market based redispatch within the meaning of Regulation 2019/943, it is unclear what other technologies will be subject to non-market redispatch actions. DWTE, and Waste to Energy plant in general are not subject to curtailment. To facilitate large penetration of non-synchronous renewables, synchronous plant must be dispatched down. To make way for non-synchronous renewables, Dublin Waste to Energy is dispatched down despite itself being primarily renewable and can be further dispatched down to make way for a handful of CCGTs in the Dublin region to meet the TSO's local reserve requirements, despite being connected to Dublin. DWTE is not aware of any other technologies that are treated in this way. Downward redispatch of DWTE, which occurs at the same time as curtailment, appears to be effectively non market-based dispatch. In either instance, in the event of market based redispatch – the unit should be permitted to bid opportunity costs, and in the event of non-market based redispatch, should be compensated as per 13(7).

NIE Networks note the omission of any consideration of generation connected to the NIE Networks' distribution network being dispatched down due to limitations on that distribution network. NIE Networks state that constraints and curtailment are transmission concepts, and as such the dispatch down of generators due to distribution network limitations does not constitute curtailment or constraint.

ESBN also raised concerns that the RAs' interpretation fails to acknowledge the full intent of the Regulation with regard to the DSO's role in dispatch and redispatch; stating that the RAs' proposal that the definition of curtailment will remain unchanged could be read to imply that all curtailment redispatch decisions will be taken by TSO, which in their view, is not consistent with the intent of the Regulation.

EirGrid and SONI are of the view that in the SEM, the concepts of dispatch, market based redispatch (or balancing) and non-market based redispatch, as considered in the Regulation, are more complex in its transposition to the SEM. Many of the concepts outlined in the Regulation and the RAs' consultation seem predicated on the view of system operations as a multi-stage process with a clearer distinction between balancing actions needed and non-market based redispatch to manage congestion issues. For example, Article 13(3) notes that non-market based redispatch may be used where no market-based alternative is available. This is not the case in the SEM where all decisions are made as a result of the Integrated Scheduling Process. The TSOs in the SEM will not take actions in advance with any clear knowledge whether the action is a balancing action or non-market based redispatch. As such, the interpretations presented may be appropriate when it comes to ex-post review and reporting but it needs to be clearly understood that this approach does not have a practical application in the central dispatch model applied in the SEM.

Regulatory Authority Response and Further Consultation Proposals

In the RAs' view, there are four key areas to consider in this further Consultation Paper based on the feedback received from respondents;

1. The interpretation of curtailment **as non-market based redispatch**, as applied to all non-synchronous units (regardless of priority dispatch status).
2. The interpretation of constraints as applied to all non-priority dispatch units **as market based redispatch**.
3. The interpretation of constraints as applied to priority dispatch units **as either market based or non-market based redispatch**.
4. Clarity on the distinction and recording of constraints and curtailment for reporting purposes.

Curtailment

The definition for curtailment used in the Consultation Paper was as follows;

'This refers to the dispatch down of non-synchronous generation for system wide reasons, where the dispatch down of all such generators would alleviate the problem. There are different types of system security limits that necessitate curtailment;

1. System stability requirements (synchronous inertia, dynamic and transient stability).

2. Operating reserve requirements, including negative reserve.

3. Voltage control requirements.

4. System Non-Synchronous Penetration (SNSP) limit'

Curtailment arises due to binding all-island system wide limits including the System Non-Synchronous Penetration (SNSP) limit or minimum inertia levels and is applied on an All-Island basis to wind and solar generation. The proposal in SEM-20-028 that curtailment, applied to non-synchronous generation regardless of priority dispatch status, is a form of non-market based redispatch was supported by the majority of respondents to the Consultation. In the RAs' view, this is the case due to the pro-rata application of curtailment and the lack of any economic indicators to determine which unit it applies to. It is proposed in SEM-21-027, published with this paper, that curtailment will continue to be applied on a pro-rata basis across all wind and solar generation regardless of its priority dispatch status.

Any changes to the nature of how curtailment is applied are not being considered as part of the implementation process for Articles 12 and 13 of the Electricity Regulation but may be considered in future, for example to facilitate a market-based process in line with the requirement in Article 13(2) for non-market based redispatching to only be used where no market-based alternative is available. No changes to the definition of curtailment are being considered as part of the implementation of Articles 12 and 13, however the RAs acknowledge that this issue was raised in a number of consultation responses and welcomes further feedback on this issue in responses to this Consultation. The differences between constraint and curtailment were approved as part of the SEM-13-011 and these definitions may need to be updated to reflect the SEM Committee's decisions as part of the process to implement Articles 12 and 13 of the Regulation. This is further discussed in SEM-21-027 in terms of the treatment of new renewable units in the SEM.

Constraints

Constraint refers to dispatch down, or redispatch, of units due to localised network reasons where only a subset of generators can contribute to alleviating the problem. These constraints result from power flow limitations due to the topology and characteristics of the transmission network and are applied to either individual or groups of units. The definition of constraints in the Consultation Paper was;

'*the dispatch down of generation due to localised network reasons, where only a subset of generators can contribute to alleviating the problem. Constraints can occur for two main reasons;*

1. More generation than the localised carrying capacity of the network.

2. During outages for maintenance, upgrade works or faults.'

Constraints as applied to non-priority dispatch units and priority dispatch units are considered in turn below;

1. *Constraints applied to all non-priority dispatch units*

The RAs are of the view that the application of constraints to all non-priority dispatch units is a market-based process. Unit commercial data, which defines the costs at which generators are prepared to increase or decrease their output, is used by the TSOs as part of the scheduling and dispatch process to both determine and minimise the cost of diverging from participants' PNs and the TSOs may dispatch units away from their PN in order to manage constraints.

Instructed deviations from submitted PNs through balancing market actions to increase or decrease output for non-energy reasons (e.g. reserves, voltage, congestion on lines, etc.) are settled at the most beneficial of either the bid/offer price or the imbalance settlement price. If the generating unit is constrained up, it will be paid the higher of the imbalance settlement price or offer price, and if the generating unit is constrained down it will pay (to buy back electricity) the lower of the Imbalance Settlement Price or bid price.

As discussed in SEM-20-028, the flagging process identifies TSO actions, referred to as a Bid Offer Acceptance (BOA), as driven by system or unit constraints (thus applying either a SO or non-marginal flag), which is then excluded from setting the imbalance price. In terms of compensation as required under Article 13(2), there are market rules in place for generators whereby if a unit is firm and is constrained below its ex-ante market position, it is compensated based on its bids and offers. If a non-firm unit is constrained below their ex-ante market position, any action to turn a unit down in the range above their Firm Access Quantity is considered an imbalance, rather than a redispatch action, as the market position of the unit is not firm above their Firm Access Quantity level. This imbalance is purchased by the generator unit at the Imbalance Settlement Price.

2. *Applied to priority dispatch units*

The RAs acknowledge the points raised by the majority of respondents concerning redispatch that is applied to all priority dispatch units as being a form of non-market based redispatch under Article 13.

Dispatchable priority dispatch units submit PNs, TOD and COD like any other unit and are compensated in line with the market rules for non-priority dispatch units, however as they are redispatched in accordance with the priority dispatch hierarchy and not on a merit order basis, their bids and offers are not selected by the System Operators to minimise redispatching costs. It is difficult to see what changes could be made to the treatment of dispatchable priority dispatch units, within the framework of Absolute Priority Dispatch in the SEM, to move to the treatment for non-priority dispatch units described above.

In the case of non-dispatchable (wind and solar) units within the current wind dispatch tool, these units are grouped together based on their effectiveness for alleviating constraints based on a measure of the change in wind/solar farm output relative to the change in the level of the constraint and do not submit TOD and COD. Such units are also currently compensated for constraints and where firm retain any ex-ante market revenue they have earned for the amount they have been constrained below their market position.

The RAs propose that redispatch applied to priority dispatch units is considered a form of non market based redispatch based on this assessment, which means that the remuneration as a result needs to comply with the requirements for financial compensation imposed by Article 13(7). In the RAs' view it would not be appropriate to compensate priority dispatch units on a different basis to the compensation arrangements in place today which provides for ex-ante market revenues, regardless of whether such redispatch is considered market based or non-market based. This point is discussed further in Section 2.3. Separate issues have been raised in this area concerning the calculation of market revenues under the PSO Levy for non-market based redispatch which is being considered separately by the CRU.

Distinction between constraint and curtailment in systems

The level of constraint/curtailment is determined by the TSOs by monitoring real time power system conditions. The application, updating and removal of constraints/curtailment is a dynamic process that considers the variability in wind production, the ability of other non-synchronous units to respond to changes in energy production and the interacting nature of constraints and curtailment.

Given the proposals outlined in this Consultation paper and the requirements under the Electricity Regulation to provide financial compensation for non-market based redispatch, it is important that the process for classification of curtailment and constraints by the TSOs is fully transparent and understood.

Currently within the TSOs' quarterly renewable dispatch down reports, the reason codes used to classify curtailments and constraints are included and within the current wind dispatch tool there is a clear categorisation between constraint and curtailment. The TSOs also revised the constraint and curtailment reports issued to renewable generators and published each quarter in 2016. It is important that this process is maintained for new renewable units without priority dispatch to ensure that there is a corresponding level of transparency for such generators, accounting for curtailment, constraints and energy balancing. This is further considered in SEM-21-027.

Regulatory Authority Proposals:

The Regulatory Authorities are of the view that;

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

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

2.3 Financial Compensation Under Article 13(7)

Consultation Proposals

Following an extensive consultation process, SEM-13-010 phased out payment of compensation for curtailment through dispatch balancing costs up to 2018. However, Article 13(7) of the new Electricity Regulation requires that financial compensation should be provided by the System Operator to units with a firm connection which are subject to non-market based redispatching. SEM-20-028 proposed that curtailment in the SEM represents a form of non-market based redispatch. Article 13(7) states;

financial compensation shall be at least equal to the higher of the following elements or a combination of both if applying only the higher would lead to an unjustifiably low or an unjustifiably high compensation;

(a) additional operating cost caused by the redispatching, such as additional fuel costs in the case of upward redispatching, or backup heat provision in the case of downward redispatching of power-generating facilities using high-efficiency cogeneration;

(b) net revenues from the sale of electricity on the day-ahead market that the power generating, energy storage or demand response facility would have generated without the redispatching request; where financial support is granted to power-generating, energy storage or demand response facilities based on the electricity volume generated or consumed,

financial support that would have been received without the redispatching request shall be deemed to be part of the net revenues.'

The RAs' considerations in terms of the appropriate level of compensation to be provided by the System Operators in the case of non-market based redispatching included the balance of risk between consumers and generators, the utility of curtailed electricity and practical considerations of the limitations on the overall level of cost recovery from consumers via network tariffs in order to invest in programmes to reduce the overall level of curtailment and facilitate higher levels of renewables on the system. In the RAs' view, these are important considerations in terms of the implementation of Article 13(7) of the new Electricity Regulation.

The high level of instantaneous renewable generation in the SEM in comparison to the majority of EU Member States was also considered, along with the focus in the Regulation on congestion management rather than specifically on curtailment as it is defined in the SEM.

The RAs set out seven options in the Consultation for compensation based on these considerations and the view that compensation up to the level of foregone financial support for all units subject to such non-market based redispatch would be unjustifiably high. All of these options provided for a limit on the level of compensation to be provided under Article 13(7) on the basis that compensation up to the level of financial support for units subject to curtailment would be an unjustifiably high level of compensation.

The Consultation did not propose any changes in terms of arrangements for compensation for constraints which are currently in place in the SEM.

Feedback Received

The majority of respondents did not agree with the RAs' proposals and argued that compensation should be based on net revenues from the DAM plus any financial support that would otherwise have been received, as this provides an incentive for the TSOs to invest in the network. Many argued that the test in the regulation is whether a generator is in receipt of an unjustifiably low or high level of compensation, not whether compensation is too high or low on an overall basis across all generators.

In their response, IWEA and NIRIG state that the purpose of Article 13(7) is to ensure that where generators are subject to non-market based redispatch they are fully compensated for the opportunity cost (or cost, as applicable) of redispatch, such that they are indifferent to whether or not they are redispatched (i.e. they are left in the same financial position). 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 to ensure 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 markets are not designed with structural barriers to the 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 IWEA and NIRIG's view the reallocation of forecasting risk for constraints and curtailment under Article 13 is welcome as the System Operators are best placed to manage and mitigate this risk, as opposed to a renewable generator owner who has no control over the future levels of constraint or curtailment once connected to the power system.

IWEA and NIRIG believe that the firmness of a grid connection has no relevance for the application of curtailment, only for constraint. In their view both firm and non-firm generators should be compensated for curtailment as to do otherwise would go against the principle of '*equal burden sharing across all wind generators, irrespective of the level of firmness / market access'.* IWEA and NIRIG also do not believe an adequate assessment of the costs of dispatch down has been completed by the RAs and the conclusions derived from this analysis are in their view invalid. IWEA and NIRIG state strong disagreement with the RAs' interpretation of what is meant by compensation being "unjustifiably high" and believe that the RAs have adopted an incorrect and unlawful test and, as a consequence, none of the options set out in the Consultation Paper can be lawfully implemented.

ISEA support the IWEA and NIRIG response in this matter and are reluctant to engage with potential mechanisms for downward redispatch, which don't provide its members with the full compensation to which they are entitled under the Regulation. ISEA does not agree that the cost of compensation is unjustifiably high and agrees with IWEA's interpretation that the compensation cost referred to in the Regulation should not be an industry wide assessment, but rather whether an individual generator has been over or under compensated.

Energia support the legal interpretation of Article 13(7) provided in IWEA and NIRIG's response to the consultation and are of the view that it is the only interpretation that is consistent with the requirements and objectives of the Article, the Regulation and the wider framework of the CEP and Energy Union and is applicable to all non-market-based redispatch (constraint and curtailment). Full financial compensation should be paid to all affected generators for the volume of energy redispatched by the system operator in the case of curtailment but limited to generators capable of the firm delivery of energy for constraints.

Coillte does not agree, in line with IWEA's arguments, that compensation under Article 13(7) represents an unreasonably high level of compensation and support the position that compensation should be evaluated at a generator level.

Bord na Mona disagree with the position taken by the RAs in relation to their interpretation of Article 13(7). In their view, the differences in reasons for non-market based redispatch in I-SEM compared to other European markets do not justify the RAs proposing to set aside the legal obligations arising from the Electricity Regulation to compensate for such redispatch. Bord na Mona believe that where a renewable or HE CHP is subject to curtailment, that compensation in accordance with Article 13(7) is due in all cases, and that compensation is due in the case of constraint, where a generator has a level of firm access associated with their grid connection agreement. In their view this should be applied retrospectively from when the Regulation came into force on 1 January 2020.

ElectroRoute are of the view that the RAs' assessment of the "unjustifiably high" cost to the consumer for compensation of non-market based redispatch is incorrect. In ElectroRoute's view, Article 13 places the onus on the TSO and DSO to improve the system to such an extent that large amounts of redispatch does not occur (and hence the compensation paid will be low) and allows generators to receive fair compensation for a system which is not fit for purpose. ElectroRoute notes that as this is an EU Regulation, it is binding in its entirety and is directly applicable without the need for any national legislation. It therefore supersedes any obligations of the SEM committee and must be strictly implemented in its entirety.

Enerco note in their response that Article 13 sets out that generators should be compensated for redispatch and believe that firmness of a grid connection offer is not relevant for curtailment, only for constraints. In their view firm and non-firm generation should be compensated under Article 13 for curtailment. Enerco note that while the level of curtailment and constraints are forecast to increase after 2024, costs for compensation will decrease as projects fall out of support schemes, provisions for non-priority dispatch renewables are implemented and as SNSP increases.

In their response ERG renewables proposed that Wind Europe's position should be taken into consideration: '*the compensation should consider both the Day Ahead Market price and the value of the lost incentive. The full compensation should be settled close to the time when the curtailment occurs and not postponed to the end of life of the plant. Compensating curtailment is the most effective way to reduce the risk of discrimination, to reduce volume-related investment risk and to ensure that the financing costs for investing in capital intensive technologies such as wind power and PV are minimized.*

There may be a benefit from not compensating 100% of the opportunity cost. Reducing slightly the income could send an important incentive signal to investors to select locations with existing sufficient network capacity, curtailment would then be likely to occur less frequently. The exact % of the opportunity cost needs to be carefully assessed in order to find a balance between an increase in policy cost and the increase of financing costs due to higher market risk. The calculation method for the amount of curtailed energy, the corresponding costs and the possible compensation must be clear and transparent'

In their response, Greencoat Capital are of the view that full compensation at the higher of the day-ahead price or the level of financial support is clearly due backdated to 1st January 2020. The RAs' basis for asserting that compensation is "unjustifiably high" is not based on a reasonable interpretation of the Regulation.

While SSE sympathise with the concerns the RAs have with regard to the potential costs associated with non-market based redispatch, they are also of the view that proposals set out under Question 15 of the Consultation do not appear to fully implement the Regulation, nor do they accurately take account of the risks faced by developers. SSE notes that generators would be faced with an untenable situation if non-market based redispatch is deemed to be "too expensive", but at the same time there has been insufficient investment in grid reinforcement to reduce redispatch volumes.

SSE is of the view that Article 13 has the ability to reduce the risk, and therefore costs, of existing and future renewable generation. Implementation of Article 13(5), coupled with targeted and proportionate incentives on network owners and operators to deliver a network that can facilitate no less than 95% of available generation, will provide the most benefit to consumers. This will also reduce barriers to entry for renewable generators through the reduction of risk to revenue streams and ultimately benefit the consumer through efficient energy prices.

In Cloosh Valley windfarm's view, the RAs are required to pay compensation, and in order to avoid paying compensation they must fully justify why the compensation is either too high or too low to market participants. It is incumbent on the RAs to carry out further studies on the potential impact and consult on the basis of those findings along with any modelling assumptions.

Innogy Renewable Ireland Limited argue that all curtailed generation (whether firm or non firm) should be eligible to receive compensation and argue that the TSOs are best placed to manage the risk of curtailment and constraints.

ESB GT are of the view that actions taken against the PNs of firm, priority generation qualifies for the financial compensation provided for under Article 13(7). ESB GT strongly disagrees with the position in the consultation that providing the compensation as set out under 13.7 (b) to firm priority dispatched generation that is redispatched results in excessively highly compensation as this is reflective only of the unit's opportunity cost and in line with the market design for all other categories of firm generation when subject to non-energy actions by the TSO.

EDFR do not agree with any of the seven compensation options in the consultation. Similar to the IWEA position put forward in their response, their view is that generators should be fully compensated for all benefits when units are curtailed, whether capacity is firm or not, and all benefits under constraint where the capacity is firm.

Codling Wind Park is of the view that the System Operators are best placed to manage and mitigate this dispatch down risk, as opposed to a renewable developer who has no control over the future levels of constraint or curtailment once connected to the power system. Reducing the uncertainty of constraint and curtailment levels for renewable developers will lead to lower prices in upcoming competitive renewable generation auctions.

Energy storage Ireland note in their response that they are concerned regarding the implication in the consultation paper that compensation for non-market based redispatching in the SEM may impact funding for investment in System Services and the DS3 programme. This sends a damaging signal to the market, has the potential to reduce investor confidence, and could impact the development of the energy storage pipeline.

BGE is of the view that there is a credible case that 'zero' compensation could be payable under Article 13(7) to firm units. Given that the operation of the system should result in only priority dispatch being on the system when curtailment is actually required and 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. They believe non-payment of generous compensation for curtailment is closer to non-discrimination between market participants, than payment of generous compensation.

In their response BGE also note that in Recital (2) of the Regulation, it is noted that the Energy Union aims to provide final customers '*with safe, secure, sustainable, competitive and affordable energy*'. In their view to cost of the objectives pursued by the Regulation to end customers should be considered.

In their view the Regulation's provisions should be applied in a way 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.

CEWEP, DWTE and Indaver all disagree with any outcome where current compensation for all forms of downward or upwards redispatch are limited or reduced arising from the integration of non-Priority Dispatch renewables. It is CEWEP's position that it is not curtailed, but it subject to non-market downwards redispatch which has equivalent priority to non-synchronous renewables (which is also a form of non-market downward redispatch). In their view, CEWEP facilities should be able to be recover their lost subsidy through either competition in a market-based mechanism, or through Article 13(7) of the Regulation when subject to downwards redispatch. CEWEP is not convinced, along with other industry associations, that the test for unjustifiably high compensation should be tested at the global industry level, but rather should be tested at the level of the individual generator.

In DWTE's view, it is clear from the Consultation Paper that the RAs have had regard to a wide range of policy considerations and obligations under domestic law in proposing the implementation of Article 13(7). The RAs are bound by the Regulation in accordance with its terms and must implement it strictly. It is clear that "unjustifiably low" or "unjustifiably high" are not associated to a burden on consumers; and any considerations in relation to the characteristics of the SEM or the jurisdictional support schemes are irrelevant considerations and it is unlawful to have regard to them.

EAI note in their response that read in isolation, Article 13 introduces an unequivocal requirement on the TSO to compensate generators for redispatch. This requirement should be discharged through a market-based mechanism but where that is not possible, the level of compensation to be paid to generators for the redispatch of their generation defaults to the approach outlined in Article 13(7). The mechanism could be viewed as one necessary to provide certainty to investors, a counter-weight to generators that are to be newly exposed to balancing risk, the correct incentives to TSOs in how they plan, build and operate the system; the level of compensation can be one way of indicating what work has to be done by the TSOs to guarantee systems capable of transmitting the large volumes of renewable energy expected under the Clean Energy Package. TSO incentives around constraint and curtailment volumes should also be considered with a view to enhancing the system to facilitate renewables.

ESBN noted that due regard should be taken for the scope within Article 13(7) for a derogation where a fixed volume of energy is not guaranteed. ESBN urge that care is taken with avail of the flexibility that was consciously drafted into the Regulation to enable the design of solutions on systems which already provide open, market-based solutions under the more challenging technical conditions arising, for example when renewable generation meets or exceeds 50% of total annual energy consumption.

EirGrid and SONI agree with the assertion of the RAs that the level of compensation as outlined is unjustified. They also question whether the connection offers made to date, combined with previous SEMC decisions on “curtailment”, are in fact a guarantee of delivery, based on the combination of the commercial terms of a connection agreement combined with the central dispatch arrangements in the SEM. In addition, given Article 13 is explicitly linked to 50% RES-E with less than 5% constraints, it is not clear to what extent compensation for levels of RES-E in excess of this figure by 2030 is applicable.

More generally, SONI and EirGrid consider that paying such compensation is not supported by a purposive interpretation of Article 13, when differences in the approach to curtailment in the SEM and continental Europe are taken into account. Because continental Europe forms part of a much larger synchronous area in which there is a very significant margin before any SNSP limits are reached, redispatch for these reasons (i.e. what would be curtailment in the SEM), is not generally required. In the current design of the SEM, because of the central dispatch and integrated scheduling model, the market position is less critical in determining the TSOs schedule, hence the use of indicators such as outturn availability that do not represent a market position.

Following review of the proposed options, EirGrid and SONI would consider that all options might be feasible to implement but believe that some of the proposals are missing an estimate of what might constitute a reasonable cost. In their view any solution should ensure that the market reflects the operational limits in a way that accounts for identified useable energy in the ex-ante market. Three options were proposed for consideration in the TSOs’ response following engagement with the NEMO service provider, to ensure that the market reflects operational limits in a way that accounts for identified useable energy in the ex-ante market. In the TSOs' view, these options better reflect the intention underlying Article 13(7), namely that compensation should only reflect a genuine loss to the generator by reference to a market position that is feasible from the point of view of both the generator and the total system (i.e. reflecting an ex ante position that takes into account SNSP limits).

Regulatory Authority Response and further Consultation Proposals

Prior to 2013, the Market Scheduled Quantity for a wind farm was equal to its real time availability and firm curtailed capacity was eligible to receive the System Marginal Price up to its availability. SEM-13-010 decided to phase out compensation for curtailment over time and this ended in 2018 with go live of the revised market arrangements.

In 2019, the new Electricity Regulation came into force and introduced a requirement, under Article 13(7), for financial compensation for non-market based redispatching from System Operators. As this Consultation Paper proposes that curtailment is a form of non-market based redispatching in the SEM, it is subject to Article 13(7). The RAs acknowledge the detailed responses and points raised in relation to this area based on the proposals in SEM-20-28 concerning the unjustifiably high level of compensation for curtailment, as a form of non-market based redispatch and also related to the discussion of constraints applied to priority dispatch units in the preceding sections of this paper. Section 2.2 of this Consultation outlines the RAs' proposals in relation to the nature of curtailment and constraints as applied to priority dispatch in the SEM.

The main issues raised by a variety of respondents are summarised into six areas below and each of these are addressed in turn before providing a summary of the RAs' position outlining the RAs' preferred proposal for compensation under Article 13(7) in order to ensure full compliance with the Regulation and address the points raised. The practical application of the proposal on Article 13(7) as outlined in this paper from 1 January 2020 is then discussed further in Section 2.4.

1. *The test to be applied in the regulation is whether a generator is in receipt of an unjustifiably low or high level of compensation, not whether the level of compensation is too high or low on an overall basis. In addition, the RAs' and SEM Committee's statutory duties to consider the impact on consumers are not relevant in this case as the Regulation supersedes any obligations of the SEM committee and must be strictly implemented in its entirety.*

While a number of respondents noted that the cost to consumers of implementing Article 13 should not be a relevant consideration for the SEM Committee, Recital 2 of the Regulation notes that *"[T]he Energy Union aims to provide final customers – household and business – with safe, secure, sustainable, competitive and affordable energy*". In the RAs' view, the Regulation is cognisant that the cost to end consumers should be considered as part of its implementation.

The RAs consider that there is no reason why the 'unjustifiably high' test established by Article 13(7) should not be applied at the aggregate level (considering the benefits and burdens of a compensation regime as a whole) as opposed to the individual level (by reference to the specific circumstances of an individual eligible generator). Compensation for constraints in the

SEM for example is implemented at a more general level, considering firmness and priority dispatch status.

The RAs have conducted revised analysis with the support of the TSOs on the overall level of compensation expected based on implementation of Article 13(7) and have reviewed levels of compensation based on different groups of generators with different levels of firmness, under different support schemes and which benefit from priority dispatch or not in line with the SEM Committee's recent decision on application of Article 12 of the Regulation (SEM-20-072). This analysis includes a number of considerations, outlined below.

The first consideration related to different units is firmness. In the SEM, a unit with non-firm access is not compensated above its Firm Access Quantity (the amount of a Participant's output which can be accommodated by the system based on network reinforcement) where its non-firm capacity cannot be accommodated on the system. If a unit is dispatched down from its ex-ante position below its Firm Access Quantity due to constraints, it is entitled to compensation. In the SEM, if a unit is firm and is constrained below its ex-ante market position the unit retains any inframarginal rent achieved from their ex-ante market revenue. Prior to SEM-13-010, non-firm generators did not receive compensation for curtailment and under Article 13(7), units that '*have accepted a connection agreement under which there is no guarantee of firm delivery of energy'* are not required to be provided with compensation for non-market based redispatch.

The second consideration relates to units which are eligible for priority dispatch or not. The aim of this distinction is to ensure that units which already benefit from priority dispatch are not overcompensated and to ensure that the total cost of compensation, in terms of the burden on consumers, is not unjustifiably high.

The RAs are of the view that both priority and non-priority dispatch units are subject to forms of non-market based redispatch, but the nature of these is not always the same and there is a value to priority dispatch that should be accounted for in determining an appropriate level of compensation for such units. The RAs are of the view that units which benefit from priority dispatch should not be overcompensated for curtailment versus non-priority dispatch units, given the expected value of priority dispatch in comparison to the treatment of new renewable units which will be subject to energy balancing and constraint actions prior to those units retaining priority dispatch.

The RAs are also of the view that units which already benefit from priority dispatch should not be overcompensated for the non-market based nature of constraints applied to them, which is driven by the way in which absolute priority dispatch is implemented in the SEM. SEM-20-072 set out the eligibility criteria for priority dispatch units pursuant to Article 12 of the Electricity Regulation. SEM-20-072 also provided for units to choose not to retain eligibility for priority dispatch and once mechanisms are in place to accommodate non-priority dispatch units in the market, such units will have the option of submitting bids and offers which will feed into economic dispatch as well as settlement.

Table 1 below looks at how different categories of units have been assessed according to these considerations.

	Dispatchable PD Units	**Non Dispatchable PD units**	**Conventional Non PD units**	**New non-synchronous units without PD**
Firmness	Units with non-firm access are not compensated for not having non-firm capacity accommodated on the system	Units with non-firm access are not compensated for not having non-firm capacity accommodated on the system	Units with non-firm access are not compensated for not having non-firm capacity accommodated on the system	Units with non-firm access are not compensated for not having non-firm capacity accommodated on the system
Curtailment compensation	Not subject to curtailment as defined in this Consultation	Prior to SEM-13-010 and phase out of curtailment up to 2018, firm units were compensated up to their availability at the SMP. Expectation of compensation for curtailment, where firm, under the Electricity Regulation	Not subject to curtailment as defined in this Consultation	New units with expectation of compensation for curtailment, where firm, under the Electricity Regulation
Constraints compensation	Compensation is based on the principle that if a generator has an ex-ante position and is	Compensation is based on the principle that if a generator has an ex-ante position and is dispatched away	Compensation is based on the principle that if a generator has an ex-ante position and is dispatched	Compensation is based on the principle that if a generator has an ex-ante position and is dispatched away from this in the balancing market due to

	dispatched away from this in the balancing market due to constraints, it should be compensated provided it has firm access. Units are settled based on the better of their complex bid offer price or imbalance price.	from this in the balancing market due to constraints, it should be compensated provided it has firm access. Units retain ex-ante market revenue for constraints. This is implemented through having a deemed Dec price of zero on these units for use in settlement, as they do not submit bids or offers in the BM	away from this in the balancing market due to constraints, it should be compensated provided it has firm access. Units are settled based on the better of their complex bid offer price or imbalance price.	constraints, it should be compensated provided it has firm access. Units are settled based on the better of their complex bid offer price or imbalance price.

Table 1

2. *Where non-market based redispatch is required, under Article 13(7) compensation received by a generator that is subject to non-market based redispatch should be no less than the remuneration received by a generator that is subject to market based dispatch.*

In the RAs' view this is an important point as it relates to the application of constraints to priority dispatch units. While remuneration should be no less than generators subject to market based redispatch for constraints, units, which benefit from priority dispatch also should not be over-remunerated for constraint actions taken by the TSOs, which are not due to a market based merit order.

On this basis, these units should only be remunerated up to the level of the market-based mechanism for compensation that is already in place. This is aligned to the RAs' considerations under point 1 above.

Article 13(2) of the Regulation is clear that units which are redispatched should be financially compensated and the current arrangements in place for compensation for constraints in the SEM in the RAs' view meet this requirement. Article 13(7) also allows for a combination of additional operating costs caused by non-market based redispatching or net revenues from the sale of electricity in the DAM/financial support received to be applied where applying only the higher amount would lead to an unjustifiably low or high level of compensation. In the RAs' view, for a priority dispatch unit subject to constraints, compensation at any higher level than currently in place would be unjustifiably high when compared to non-priority dispatch units and would ignore the value of priority dispatch rights.

3. *That the firmness of a grid connection has no relevance for the application of curtailment, only for constraint and all generators should be compensated for curtailment regardless of firmness.*

Appropriate rules are in place in the market for compensation associated with constraints applied to firm units and these arrangements support locational investment signals for generators to locate in less constrained areas. In terms of curtailment, some respondents have argued that compensation should be provided regardless of a unit's firmness, due to its pro-rata nature and the lack of any locational signal associated with curtailment. Up to the phase out of payment for curtailment under the old market arrangements in 2018, compensation based on the system marginal price was only ever paid to firm generators.

In the RA's view, the Regulation is clear and states '*Where non-market based redispatching is used, it shall be subject to financial compensation by the system operator requesting the redispatching to the operator of the redispatched generation, energy storage or demand response facility except in the case of producers that have accepted a connection agreement under which there is* ***no guarantee of firm delivery of energy****.'*

The RAs reiterate the point made in SEM-20-028 that redispatching in most European countries is associated with resolution of congestion issues only, where networks can be developed further to resolve recurring congestion. In contrast, in the SEM, curtailment is required to respect SNSP limits and other system wide issues due to the small synchronous area of the SEM. This cannot be addressed through the other provisions in the Regulation to resolve network congestion. On this basis, in the RAs' view it would be inappropriate to provide a higher level of compensation than provided for in the Regulation for non-firm units.

Article 13(5)(a) is also of relevance here, which requires system operators to guarantee the capability of transmission and distribution networks to transmit electricity produced from renewable energy sources or high-efficiency cogeneration with minimum possible redispatching, unless electricity from such sources represents more than 50% of the annual gross consumption of electricity.

As part of this Consultation, feedback is being sought on the proposal to only compensate firm generators for non-market based redispatch associated with curtailment.

4. *That the TSOs are best placed to manage the risk of curtailment and constraints and should compensate for these in order to provide certainty to investors and to correctly incentivise the TSOs in how they plan, build and operate the system in order to transmit the large volumes of renewable energy. Consideration of further TSO incentives to improve constraints and curtailment may be warranted as part of this.*

The RAs acknowledge this point, made by a significant number of respondents to the Consultation. While TSO incentivisation is not the subject of this paper and is the responsibility of each RA in relation to the jurisdictional SONI and EirGrid price controls, this issue will be considered further with the relevant parties in each Regulator.

The RAs also acknowledge that this area may need to be considered further where in future the DSOs may have a role in dispatch and redispatch in the SEM.

5. *That decisions 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.*

The RAs strongly support this argument. The recitals of the Electricity Regulation recognise the importance of integration of renewable energy and driving long term investment in order to deliver the objectives of the Energy Union and 2030 climate and energy framework. They also note the importance of market-based incentives for investment and Article 3(g) states that '*market rules shall deliver appropriate investment incentives for generation, in particular for long-term investments in a decarbonised and sustainable electricity system, energy storage, energy efficiency and demand response to meet market needs, and shall facilitate fair competition thus ensuring security of supply'*.

The RAs agree that the Regulation is aimed at facilitating further decarbonisation while ensuring solutions are as far as possible market based and with a level playing field between market participants. It is clearly not the Regulation's intention to improve the financial situation of units where investments have already been made, but to encourage longer term investment signals for renewables. This point is reflected in the RAs' proposals in this section related to compensation proposals for existing units benefitting from priority dispatch rights and the treatment of compensation for constraints.

6. *That any solution should ensure that the market reflects the operational limits in a way that accounts for identified useable energy in the ex-ante market and that compensation should only reflect a genuine loss to the generator by reference to a market position that is feasible from the point of view of both the generator and the total system.*

Across Europe, levels of redispatching have increased along with the large scale integration of renewables, with impacts on congestion patterns, redispatch volumes and costs. This mainly relates to constraints and as discussed in SEM-20-028, the concept of curtailment is currently unique to the SEM in the context of a small synchronous area with high levels of non-synchronous generation.

The current Internal Energy Market design is based on a set of defined bidding zones (one of which is the SEM) and cross zonal interconnection. Clearing prices in the Ex-ante markets, calculated by the pan-EU price coupling algorithm in the DAM, reflect the marginal value of electricity in each bidding zone with only constraints across interconnectors being considered.

Internal constraints, or curtailment, within bidding zones are not considered within this calculation and redispatching actions taken by TSOs as a result of the need to adjust market outcomes to ensure secure system operation are increasing, resulting in additional costs for consumers. The Electricity Regulation aims to address this issue by considering structural congestions within bidding zones as part of the rationale for bidding zone splits within the zonal market design, as an alternative to further developing network infrastructure. However, the actions required within the Regulation to help resolve internal congestion do not address the issue of curtailment as it arises in the SEM.

In other EU markets, two main processes for redispatching have been implemented or are understood; market based redispatch and cost based redispatch. In market-based redispatch, market participants can provide bids to TSOs for being moved from their market position for the purpose of congestion management, with bids being selected on a merit order basis in order to resolve the congestion. In cost-based redispatch, market participants may be required to participate in redispatching and generators which are required to ramp down pay back their short run marginal costs but retain their ex-ante market revenue, while those required to ramp up are compensated for their additional costs. In many cases, a combination of both approaches exists within different markets and Article 13 of the Regulation attempts to introduce some common rules for redispatching across Member States.

A recent study by the Belgian Regulator, CREG[6], identified the issue of increased redispatching and its impact on the efficient operation of the market, along with its resulting distortion of market prices. CREG's study found that redispatching distorts price signals as units which are not technically able to produce electricity may take part in the price formation process while units which are actually producing are remunerated outside the ex-ante market (through upwards redispatch as renewables are constrained for example). In their view, this results in electricity prices that do not reflect actual supply and demand where units are systematically redispatched down after clearing in day-ahead market coupling due to structural congestions. This reflects an issue which has been raised in the TSOs' response to SEM-20-028 in relation to ensuring that the market reflects the operational limits associated with SNSP levels in the SEM.

As a potential solution to this, CREG proposes the introduction of redispatching actions before day ahead market clearing takes place, to prevent units which are likely to be redispatched downwards after day-ahead market clearing from participating in market coupling (with compensation for such units based on their opportunity cost). This would be applied to certain units when the probability of downwards redispatching exceeds a certain threshold, for example during periods of high wind. This would depend on the TSOs' ability, based on system conditions, to accurately forecast which units will be required to be redispatched down.

In their view, this would reduce the total volume of redispatching required with less need for upwards redispatching after market coupling takes place, as such units would be selected in the market to meet the energy requirement. In order to introduce this type of redispatching, TSOs need to be able to accurately forecast which units will likely be required to be redispatched given prevailing system conditions.

This type of approach has also been suggested in a recent study on integration of the day ahead market and redispatch[7], which identifies the issue of a zonal electricity market design where generation is redispatched after market closure to manage congestion within bidding zones, while congestion between zones is managed ex ante through market coupling. In this approach, ex-post redispatch is minimised by integrating preventative redispatch into the day ahead market. Generators would be selected for redispatch ex-ante based on their expected effects on either constraints or curtailment and compensated at their opportunity cost, i.e. what they would have earned in the day ahead market. This would reduce the costs of ex-post

[6] https://www.creg.be/sites/default/files/assets/Publications/Studies/F1987EN.pdf
[7] https://www.sciencedirect.com/science/article/pii/S030626192031165X

redispatch and would incentivise the TSOs to forecast constraints and curtailment as accurately as possible.

In Germany, the management of domestic grid congestion occurs outside the market with generation and storage facilities compensated for costs incurred and profits foregone when instructed to increase or decrease generation to avoid network congestion. The determination of remuneration is complex with a detailed industry guide for calculating compensation by generators to be submitted to the TSOs for assessment on an ex-post basis. It is interesting to note that the redispatch of supported generation by German TSOs and the total level of support received by renewable generators are closely integrated.

In Spain, redispatch is managed as part of a two-stage process based on generator bids, which are settled at a unit's bid price for upwards redispatch and at the hourly day-ahead spot price for downwards redispatch. The TSO can also redispatch in real time with all bids and offers settled at a unit's bid price.

In their response to SEM-20-028, the TSOs proposed a mechanism to account for the difference between the ex-ante market schedule and management of curtailment and constraints and have provided the RAs with comparative analysis of total cost estimates in terms of the energy, capacity and system services markets along with redispatch and renewable energy support costs based on their proposal to limit the amount of non-synchronous generation that can clear in the ex-ante markets versus the status quo as more renewables are connected to the system towards 2030. EirGrid and SONI have also raised the issue of the deviation between the ex-ante market and useable energy in the TSOs' schedule which is distorting the energy market, dispatch balancing costs, capacity market and system service outcomes. While it is expected that many of these issues will be addressed through meeting the schedule to increase SNSP levels by 2030, in the short to medium term this is leading to significant market distortions.

The RAs support the TSOs' concern that if some portion of the non-synchronous generation scheduled in the ex-ante markets can never be delivered due to SNSP limits it could be questioned whether consumers should be paying for energy that they cannot use. This is in line with the SEM Committee's existing policy that this is an unreasonable burden on consumers.

In their response, EirGrid and SONI propose that the market should reflect current operational limits in a way that accounts for identified useable energy in the ex-ante market, through placing a cap on the amount of non-synchronous generation that can clear in the ex-ante markets. Their response includes three options to implement such a proposal but based on further discussions the RAs understand that this would involve a limit on the total non-synchronous generation that can be scheduled in the DAM, based on the SNSP limit at the time[8]. This represents the proportion of non-synchronous generation that can be accommodated securely. Where non-synchronous generation exceeds the limit, some of this volume would not be scheduled and receive no revenue from the ex-ante markets or compensation for redispatch.

The RAs acknowledge the important issues raised in the TSOs' response which are supported by ongoing discussions in other markets but are concerned 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. This could also be viewed as an intervention in the operation of the ex-ante market contrary to the principles contained in Article 3 and 12 of the Electricity Regulation. In contrast, a wider proposal to introduce redispatching at the ex-ante market stage which could be applied to any type of generator and with some level of compensation reflecting ex-ante revenues could align with the intent of Article 13(7) and treat all units in the same way.

The difficulty in considering these issues is that they are at an early stage of consideration at an EU level and the current proposals described would need to be adapted to the SEM. For example, the idea of preventative redispatching in the ex-ante markets (with compensation) could be applied to predictable constraints, curtailment, or both in the SEM. This approach would only be beneficial if the TSOs could accurately forecast where units would be required to be redispatched down.

The second issue relates to actual implementation by the TSOs and whether either solution would be more costly to implement than the issues it attempts to resolve, particularly in the context of current targets to increase SNSP levels by 2030. The net impact on costs to consumers is very difficult to establish, despite extensive analysis carried out by the TSOs in this area, in both the TSOs' proposal and the EU proposals which have been reviewed and

[8] System Non-Synchronous Penetration is the extent of power injection which is not synchronised on the grid due to being based on direct current power system electronics, such as wind/solar power or interconnector imports, compared with the total amount of power being drawn from the system, such as demand consumption or interconnector exports. This is generally expressed as follows -
•SNSP = (Non-Synchronous Generation + Net Import) / (Demand + Net Export);
Based on studies for the high levels of non-synchronous renewables connecting to the system, it was found that a limit needs to be placed on this factor in order to maintain system stability through power system inertia and other system security requirements.

may have significant effects on price formation in the DAM and on prices required by generators in the Capacity Market.

In addition, under the proposal to introduce a limit for non-synchronous generation, the loss of revenue for expected available generation would not have been anticipated by past or current investors for renewable energy in the SEM and may increase the risk associated with investment or impact on the viability of projects, which may negatively impact on the investment context and renewable energy targets in both jurisdictions. This could damage the economic viability of existing capacity based on the way existing renewable support schemes have been designed for example. If the limit only applied to new capacity where the investment decision was made knowing that access to the DAM would be limited, then all of the loss of income from curtailment would fall on such capacity damaging any potential investment case.

The RA recognise that there is significant value in the TSOs' proposal and that the issue of the difference between the ex-ante market schedule and feasible dispatch requires further consideration. The RAs intend to further assess these issues as part of a range of measures being considered to mitigate curtailment in the SEM. This is discussed further in Section 2.5.

RA Proposal based on these considerations

Based on this assessment and responses received to SEM-20-028, the RAs have determined a preferred option for compensation arrangements for curtailment as part of this Consultation.

The impact assessment for the electricity Regulation[9] foresaw minimum rules for compensation for redispatch being introduced based on compensation of additional operating costs or a '*high percentage of lost revenues'*. It also noted that ensuring compensation for curtailment for RES-E would increase costs to be borne by System Operators, but that overall costs should remain similar if they are currently integrated into renewable subsidy schemes. It should be noted that existing renewable subsidy schemes in Ireland and Northern Ireland were developed before Article 13(7) came into force, in particular the REFIT and ROCs schemes. Considerations in relation to how to account for these costs within support schemes are out of scope of this Consultation.

This proposal looks to implement the principles of the Regulation while ensuring that there is no overcompensation of certain units, based on the assessment outlined in this section on

[9] https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52016SC0410

different unit types, the value of priority dispatch and revenues in the market. These options account for the following provisions, which have been discussed in earlier in this section;

1. The definition of non-market based redispatch in the SEM.
2. The treatment of firmness under Article 13(7).
3. The value of Priority Dispatch rights in the SEM.
4. Consideration, as per SEM-20-028, of any unjustifiably high level of compensation
5. The unique application of curtailment in the SEM linked to the level of SNSP, as opposed to redispatch for congestion management in other EU Member States.

In determining a preferred option for Consultation, the RAs have considered a range of compensation arrangements based on additional operating costs caused by redispatching, the applicable DAM price at the time units are redispatched and total foregone revenues including financial support due to redispatching. These are based on the RAs' previous assertion in SEM-20-028 that Article 13(7) allows for a combination of additional operating costs caused by non-market based redispatching or net revenues from the sale of electricity in the DAM/financial support received to be applied where applying only the higher amount would lead to an unjustifiably low or high level of compensation. The estimates for compensation are based on different scenarios for levels of curtailment, generation portfolios, eligibility under each support scheme and levels of firm access.

The RAs are of the view that units which benefit from priority dispatch should not be overcompensated for curtailment versus non-priority dispatch units, given the expected value of priority dispatch in comparison to the treatment of new renewable units which will be subject to energy balancing and constraint actions prior to those units retaining priority dispatch. Priority dispatch units benefit from a reduced financial impact associated with the application of redispatching following other units and also impose additional redispatching costs on the system as a whole. Based on the above considerations, the RAs propose to compensate priority dispatch and non-priority dispatch units differently 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.

SEM-20-072 set out the eligibility criteria for priority dispatch units pursuant to Article 12 of the Electricity Regulation. SEM-20-072 also provided for units to choose not to retain eligibility for priority dispatch and once mechanisms are in place to accommodate non-priority dispatch units in the market, such units will have the option of surrendering their priority dispatch rights.

The RAs propose that all units that are currently eligible for priority dispatch would receive compensation for non-market based redispatch (in relation to curtailment), where firm, up to the level of their additional operating costs caused by redispatching pursuant to Article 13(7)(a). Based on the understanding that the marginal cost of non-synchronous units subject to curtailment is minimal and the Curtailment Price would continue to apply, these units would also have the opportunity to benefit from the same treatment as new units outlined below if they chose to surrender their priority dispatch rights. This is linked to the implementation of market changes to facilitate non-priority dispatch renewables set out in SEM-21-027.

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

The proposal to compensate non-PD units up to the DAM price is based on a number of considerations;

1. Based on the level of compensation paid to units for curtailment under the previous market arrangements and to broadly reflect the current arrangements in place for compensation associated with constraints where a generator is dispatched away from an ex-ante position.
2. Based on a review of compensation arrangements in place in other jurisdictions associated with redispatch, accounting for the unique nature of the SEM in terms of redispatch for curtailment versus internal congestion management.
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.

The RAs also acknowledge the uncertainty associated with levels of curtailment as we move towards higher levels of renewables on the system and the importance of system services, storage, flexibility and SNSP in continuing to achieve decarbonisation goals. This involves a risk to parties affected by curtailment, providing compensation for curtailment and for consumers which the RAs intend to monitor following any decision on implementation of Article 13(7). There are set targets in place to increase the level of SNSP to 75% by the end of 2021 and the TSOs plan to operate the system at SNSP levels of up to 95% in future in order to accommodate significantly higher levels of renewables. This may entail some enduring level of curtailment and a continued issue of alignment of the market with operational and system security requirements.

On this basis, the RAs are also considering whether a limit on compensation under Article 13(7) could be included in future to account for the higher targets of SNSP and levels of non-synchronous generation which can be physically accommodated on the system. This would account for the limits at which the all-island transmission system is operating at in comparison to other systems in the EU. As part of the final decision in this area the RAs intend to introduce a provision for review of these decisions based on the levels and cost of curtailment over time, while working with the TSOs and other stakeholders to mitigate increased curtailment as much as possible.

Regulatory Authority Proposals:

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

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

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

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

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

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

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

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

2.4 Application of Proposals from 1 January 2020

Consultation Proposals

The RAs noted in the Consultation that they were cognisant that the requirement for financial compensation for non-market based redispatching under Article 13(7) came into force on 1 January 2020.

As the determination of the appropriate level of compensation is an important part of this Consultation Process, the RAs welcomed feedback on when such changes should be implemented. The Consultation did not go into detail on proposed mechanics for compensation which are discussed in this section.

Feedback Received

The majority of feedback received, in line with the feedback received under Section 2.3 of this paper, is that compensation should be paid to eligible units from 1 January 2020 and that to do otherwise would not be compliant with the Regulation.

Regulatory Authority Response and Further Consultation Proposals

The RAs acknowledge the points raised in relation to this issue along with the challenge of implementing a system of payments based on the proposal outlined in Section 2.3 in order to meet this requirement.

On this basis, the RAs propose two options to implement an ex-post system of payment for non-market based redispatch associated with curtailment from January 2020. The first option would be for the TSOs to compile information on the level of curtailment for each market time unit across the year which would have been applied on a pro-rata basis across all relevant units. This could then be compared against relevant DAM prices and expected DAM revenues. Depending on whether units are compensated up to the level of the DAM price, or up to the level of additional operating costs by such units when curtailed, their total payment for the year could then be calculated.

A second option would be for individual generators to submit information on the level of non-market based redispatch associated with curtailment (in line with the SEM Committee's definition) and their calculation of payments due in line with the SEM Committee's Decision on compensation levels from 1 January 2020 until 31 December 2020. This would then be assessed by the TSOs for compensation to be paid on an ex-post basis line with the principles to be decided based on the proposal in Section 2.3. This would be similar to the process in place in Germany, where remuneration for non-market based redispatch is dealt with bilaterally between generators and TSOs, with invoices submitted based on costs incurred to be evaluated by TSOs. As part of the SEM Committee's Decision on this issue, a reporting template would be published in an Annex including the requirements and detailed information for requesting any payments associated with non-market based redispatch.

Under either option, it is expected that there would be no change required to the CCURL cashflow for curtailment under the Trading and Settlement Code, which ensures that the curtailed quantity is priced at the same price as it was traded in the ex-ante market. The result of this is that no revenue will have been received or lost through the combination of the ex-ante markets and the Balancing Market as a result of the Curtailment. This would need to be amended if on an enduring basis changes were made to market systems to accommodate this payment.

The RAs would also welcome proposals from the TSOs for an ex-post payment mechanism in line with the option set out in Section 2.3.

SEM Committee Proposed Decision:

- The SEM Committee has outlined two proposals for an ex-post payment mechanism and welcomes feedback on this from interested stakeholders, including alternative proposals.
- It is expected that under either mechanism, no change would be required to the treatment of Curtailment within the Trading and Settlement Code.

2.5 Consideration of Mitigation of Non-Market Based Redispatch

Section 2.3 set out a range of issues being considered in terms of the overall level of redispatch in the SEM and across Europe. The RAs are cognisant of the importance of mitigation measures for redispatching in the SEM, in particular for curtailment, in order to increase the overall level of renewables and reduce the cost burden associated with dispatch balancing costs and further costs under Article 13(7).

The Future Arrangements for System Services, which are currently being developed by the SEM Committee, aim to support increased levels of renewable energy on the system. This will be a central area of importance in order for the TSOs to operate the system at SNSP levels of up to 95%, reduce the inertia floor and minimum conventional generation requirements and implement a RoCoF limit of 1Hz/s.

The RAs have commenced further work in on order to identify other additional mitigation measures and the interactions between the considerations in this paper and broader market design.

3 Next Steps

Comments are invited on this further Consultation Paper until 02 July 2021 and can be sent to gkelly@cru.ie and Gary.Mccullough@uregni.gov.uk. All non-confidential responses will be published with the SEM Committee's Decision in this area.