Enerco Energy Ltd,
Lissarda Business Park,
Lissarda,
Co. Cork
22nd June 2020

Re: Consultation Paper on the Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch

Dear Gina and Gary

Firstly, thank you for the opportunity to comment on the Implementation of Regulation 2019/943 in relation to Dispatch and Redispatch. Enerco Energy and Ireland's largest independent wind energy generator with over 500MW of wind assets currently operational and with a significant pipeline of assets in construction.

Background and Context

With its existing projects Enerco Energy has contributed significantly to the steps taken to achieve the Republic of Ireland's efforts to meet its 2020 Renewable targets, and we are keen to be part of the solution in achieving the forthcoming 2030 targets.

Enerco Energy have been active in discussions SEMO and the Regulatory Authorities on this topic and applaud the decision to consult on Articles 12 and 13 together to ensure that a clear, coherent and streamlined solution is found. By doing so the regulation can be delivered in full in a fashion that minimises costs to the end consumer.

This response is submitted by Enerco Energy and reflects our own particular views, it should be noted that we are actively engaged as a member of IWEA and strongly endorse IWEA's response to this paper. Given the length and complexity of this consultation we have focused our response on those questions where we feel our knowledge and expertise will add most value.

We believe that Articles 12/13 of the Clean Energy Package can be delivered as follows:

- Article 12 – Creation of non-priority dispatch wind
- Article 13 – Compensation for dispatch down for priority dispatch wind when curtailed and when constrained and the capacity is firm

From the outset we are keen to emphasise that the Clean Energy Package is a regulation, not a directive, and so the deliverance, in full, of Articles 12 & 13 is required by European law from the date of entry into force, that is, January 1st 2020. It is important to note that the full implementation of Article 13 will substantially reallocate a significant risk faced by wind developers towards the System Operator – that of constraint and curtailment. In our view this reallocation is welcome given the relative ability of the System Operators to manage and mitigate this risk. This will lead to lower prices in the upcoming competitive renewable schemes and a consequent reduction in the PSO levy, benefiting the end consumer. It will also focus action of the System Operators towards the timely resolution of the underlying system limitation driving their constraint and curtailment actions.

Furthermore, Article 13 can identify, and put a market value on, the requirement for specific pieces of transmission infrastructure, which can be used to help define the need for transmission and distribution infrastructure investment in future.

In the response below we summarise Articles 12 and 13 of the Clean Energy Package individually, before looking at how, in our view, they can be implemented together in the most coherent fashion. The consultation is then considered before our thoughts are summarised.

Article 12

Article 12 provides for ending the designation of all but the smallest renewable generation projects as Priority Dispatch. Priority Dispatch is a status granted to certain technology types under the SEM and is a key pillar of the market. In the absence of an appropriate treatment the ending of Priority Dispatch could result in a two-tier system for scheduling renewable generation where there is a great risk that by dispatching down newer units ahead of older units. The burden of constraining and curtailing such units could then make their business cases inviable. Consequently, these units would not be built, and the 2030 targets will be missed.

Under Article 12 there is provision for the Priority Dispatch status of renewable generation to be amended. Enerco believe that allowing units to opt out of priority dispatch will cause them to run less frequently at times where priority dispatch generation is very high. The reduction of such generation, at such times, would lessen the requirement for accepting in re-dispatching units in the balancing market, thus reducing the impact on the end consumer. This is especially important for units under the RESS scheme where their contract for difference is not paid when price is below €0/MWh, or for older units that no longer receive out of market support.

Opting out of priority dispatch will require non-trivial systems changes and user learning for those choosing to do so. Consequently, it is vital that this is on an optional, rather than mandatory, basis, which could exclude smaller players from the market. However Enerco is strongly of the view that current system limitations should not be allowed to determine the direction of future policy, it is core to the Recast Electricity Regulation that renewable generation, as an increasingly significant proportion of the generation market, be afforded full access to trade in the internal market.

Units opting out of priority dispatch will be required to submit Commercial and Technical Offer Data (COD and TOD) and respond to dispatch instructions form the system operator. This occurs at present in a limited form through the application of constraint and curtailment instructions, using the Wind Dispatch Tool. It is vital that this system is used in order to minimise the impact to market participants and the market operator. Due to its extremely manual nature and the fact that wind units do not use EDIL at all at present the use of EDIL would cause very significant disruption to both participants and the market. This would make it very difficult, and complex to use, simply put, EDIL is not an appropriate tool for this purpose. The use of the Wind Dispatch Tool, which is functioning well in situ, will prevent issues such as faulty dispatch instructions from the system operator and erroneous response to such instructions from participants. This would then avoid further issues in settlement, the first 20 months of I-SEM have illustrated how strongly this should be avoided.

Even after non-priority dispatch units are fully utilised it is possible that there may still be a requirement for priority units to be dispatched down, as seen today. To ensure fair and even burden sharing this should continue to be applied on a pro-rata basis among "new" and "old" priority dispatch units. This is so as not to adversely affect the business cases of new units, which would risk compromising the 2030 targets.

Article 13

Given that priority dispatch units do not bid into the balancing market it is clear that constraint and curtailment are non-market redispatch, which is reinforced by Paragraph 3 of Article 13 of the Clean Energy Package.

Article 13 sets out that generators, who have a route to market agreed prior to July 4th 2019 should be compensated for redispatch; including any financial support, (such as REFIT, ROCs or Corporate PPAs) foregone as a result, unless they have accepted a connection offer with no guarantee of the firm delivery of power. We can see no basis for the assertion in the consultation that constraint action can be considered as market based redispatch. 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.

Further, we strongly believe that firmness of a grid connection is not relevant *for curtailment, only for constraint* and, as such, both firm and non-firm generation should be compensated under Article 13 *for curtailment.*

It is important to emphasise that, as the I-SEM market has not received a derogation from Article 13, it has to be applied from Jan 1st, 2020, and relevant generators need to be compensated from this date, as to do otherwise is in breach of EU law.

Whilst outside the direct scope of this paper it is essential that wind developers are not then forced to hand back these revenues under R factor reconciliation. This could be done simply by excluding the CDISCOUNT and CCURL charges from the R factor reconciliation. Put simply, compensation that is then taken away is not compensation at all.

Optimisation of Articles 12 and 13

Article 12 provides the opportunity for out of benefit units and RESS units not to run at times where price is negative, which would mean that they incur a loss; whilst Article 13 provides compensation for in benefit units to be compensated for the full value of their lost generation – i.e. including out of market payments such as REFIT, ROCs or Corporate PPAs.

Enerco believe that these payments should be recovered in a fashion that is fair and equitable to all and which could be implemented by a modification to the Trading and Settlement Code. As noted above, given that the I-SEM market does not have a derogation to the Clean Energy Package which went live on January 1st, 2020 the compensation would need to be effective from January 1st, 2020.

A carefully considered implementation of Articles 12 and 13 could create a virtuous cycle benefitting in benefit and out of benefit renewables and minimising the charge to the end customer. Furthermore, by reducing the risk to units being developed in future such as those bidding under the RESS scheme in Ireland, it will enable them to reduce their prices, providing still further benefit to the end consumer. This will provide an improved investment signal for renewables, aiding the efforts of the Republic of Ireland and Northern Ireland to reach their 2030 climate targets.

The fact that this would reduce the volume of acceptances on priority dispatch units, by moving the accepted volume to non-priority dispatch units, would alleviate the issues that arose under the highly contentious Modification 10_19 which was rejected by the Modification Committee and then implemented by the SEM Committee. It would also ensure more acceptances were made on a market basis, enhancing the transparency of the market signal provided by the balancing market.

Responses to Questions posed in the Consultation paper

Consultation Question 1*: Do you agree with the RAs' interpretation of the requirements under Articles 12 and 13 and specifically the application of dispatch, redispatch and market based/non-market based redispatch in the SEM?*

We agree with the scheduling and dispatch process outlined in Figure 3 (Page 15) of the consultation that constraint and curtailment are considered redispatch. Enerco agree that curtailment is considered non-market redispatch and strongly believe that constraint is also non-market redispatch.

On Page 13 (last paragraph) the Regulatory Authorities state that "The RAs are of the view that in the case of the application constraints, as these take into account of Commercial and Technical Offer Data submitted by Participants to minimise the cost of diverging from PNs, this is a form of market based redispatched". However, wind units do not currently submit commercial and technical offer data, *therefore, for wind units, constraints cannot possibly be market based redispatch and therefore must be non-market based redispatch.*

There may be the misapprehension that the TSO's 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. Furthermore, this is a price *deemed* by the Trading & Settlement Code not a *market* price submitted by a participant, as a result this cannot be market based redispatch.

Consultation Question 2*: In terms of the practical implementation of Article 12(1) to introduce a distinction between units which retain eligibility for priority dispatch and those which are not eligible, the RAs propose;*

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

Enerco agree with the Regulatory Authorities on the first two point and very strongly believe that generators that fall under the third point must also be eligible for priority dispatch.

The non-applicability of priority dispatch to generators commissioned post July 4th, 2019 is "*Without prejudice to contracts concluded before 4 July 2019*". It is our position that the *"Without prejudice"* seeks to achieve protection for active projects with a clear route to market that are actively making progress on financing and commissioning. The most objective measure of this is a windfarm that can demonstrate evidence of a route to market, such as a REFIT Letter of Offer or a CPPA before 4th July 2019.

Developers that have made material investment in the expectation of certain market and/or subsidy interactions for such projects, and correspondingly such generation once constructed and operational should continue to benefit from full priority dispatch. For the avoidance of doubt, a generator would not qualify for priority dispatch should it become commercially operational under a different route to market, e.g. progressed with RESS in place of REFIT.

The second point is more complex as it is likely to include units which operate under the RESS scheme. Such units will only be remunerated to their contract price if the Day Ahead price is greater than or equal to zero. As such these units will need to be able to forego priority dispatch to avoid having financial losses inflicted on them if they cannot turn off in such circumstances and so should not be consider priority dispatch.

***Consultation Question 3**: It is the RAs' understanding that any unit which is non-renewable dispatchable but is no longer eligible for priority dispatch can be treated like any other unit within the current scheduling and dispatch process, through submission of PNs with an associated incremental and decremental curve. Feedback is requested on this aspect of implementation of Article 12 of the new Electricity Regulation.*

Enerco agree with the Regulatory Authorities in this respect.

***Consultation Question 4**: It is proposed that any unit which is non-dispatchable but controllable and is no longer eligible for priority dispatch would run at their FPN, be settled at the imbalance price for any volumes sold ex-ante and could set the imbalance price.*

We would begin by wishing to clarify that in Question 4 the difference between traded and metered volume would be settled at the imbalance price and not the entire FPN volume as the question appears to imply.

Wind units which are out of benefit, or which operate under the RESS scheme need to behave quite differently to those in benefit, including ROCs or REFIT. Specifically, such units would not wish to sell at sub-zero prices in the ex-ante markets and would only wish to spill into the balancing market where price was above zero, as to do otherwise would force them to lose money.

It is imperative that a non-priority dispatch renewables unit category exists before the first unit under RESS begin operating in the market. Existing units should remain priority dispatch until they choose to become non-priority dispatch units. New units, aside from those covered in our answer to Question 2, above, should automatically become non -priority dispatch renewables.

The introduction of such a category of unit is implicitly required under the recast regulation and should significantly reduce the costs to the system operator, and ultimately the end consumer, of dispatching down renewable units under Article 13. This is because non-priority units will not choose to run at times when they would lose money, taking a potentially large volume of renewables off the system at such times and reducing the need to redispatch priority dispatching units. Furthermore, it would provide what is likely to be a much cheaper dispatch down option for the system operator when out of merit units have been able to sell their generation in the ex-ante markets they will not need to recoup lost benefit revenue when being bid down.

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

Whilst it is generally recommended that the TSO would use the FPNs of the units as submitted to them, given that the generator is "at the coal face" this would not be essential as long as the generator was not subject to a potential information imbalance charge.

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

We do not believe this is an acceptable solution as there will be a difference between out of merit renewable units, for whom this could broadly be used, (though noting that they will incur some costs by reducing output and being off load) and units under the RESS scheme which will, where the ex-ante market price is less than €0/MWh, lose their CFD benefit and be forced to incur a loss.

***Consultation Question 5**: Feedback is invited from interested stakeholders on the treatment of non-dispatchable and non-controllable units.*

It is our belief that for existing small volume of non-controllable non dispatchable generation the existing market rules should continue to apply

***Consultation Question 6**: Do you agree with the RA's interpretation that new generators which are no longer eligible for priority dispatch (both dispatchable and non-dispatchable but controllable) will be subject to energy balancing actions by the TSOs, considered in dispatch economically and settled like any other instance of balancing energy?*

***Consultation Question 7**: What is your view on the application of bids and offers to zero marginal cost generation?*

***Consultation Question 8**: What is your view on a potential rule-set being implemented for non-dispatchable units where (a), systems cannot facilitate ranking of decremental bids for such units for balancing actions for a certain time period and/or (b) where convergent bid prices require a tie-break rule?*

Units that currently have priority dispatch, which are controllable and are either dispatchable or non-dispatchable should in future have the option, but not the obligation, to forego priority dispatch. If the option to forego priority dispatch is chosen, these units should have the same responsibilities and opportunities in the balancing market as units which are currently non-priority dispatch.

If opting to forego priority dispatch such units should be obligated to submit both commercial and technical offer data, with the units choosing whether to submit simple or complex commercial offer data and being settled for dispatch away from their PNs in the same way as any other unit.

For these units, the concept of rule sets on bid ranking and tie breaking will cease to exist as they will be treated like any other. Specifically, the system operator should be able to dispatch all such units to achieve their requirements in the most optimal fashion, regardless of fuel type.

Where non-priority dispatch wind units are able to fairly reflect the cost of their lost generation through simple bids and offers as part of their Commercial and technical offer data Enerco believe that they should be dispatched on a market basis like any other units. Furthermore, as such units would be treated like all others, the tie-break will cease to apply, and the system operator should dispatch such units in the fashion most suited to the system at that time.

Consultation Question 9*: Do you agree with the TSOs' proposal for a revised priority dispatch hierarchy?*

The RAs request that the TSOs consider the points raised in this Section in their response with any further proposed changes to the hierarchy

Consultation Question 13*: Do you agree with the RAs' interpretation of Article 13(6) and the introduction of a new hierarchy for the application of non-market-based downward redispatching?*

We have taken Questions 9 & 13 together here; in that we believe that a single hierarchy is required. As noted throughout we believe that the introduction of a non-priority dispatch category for renewables will substantially decrease the need to redispatch priority dispatch units but that where this is required the hierarchy should be as follows:

- Non-priority dispatch, whether conventional or renewables, would be dispatched down first on a market basis
- High efficiency Cogeneration / Biomass / Waste to Energy would then be redispatched
- Wind / Solar / Tidal / Hydro would then be dispatched on a non-market basis
- Interconnector profiles would then be amended
- Finally, generation where redispatch results in safety issues arising from the operation of hydro generation in flooding situations would be redispatched as a last recourse

Consultation Question 11*: The RAs' interpretation of the Regulation is that where a new connection agreement is required or where the generation capacity of a unit is increased, a unit will no longer be eligible for priority dispatch.*

The RAs also propose that units should be able to make a choice on whether they wish to retain their priority dispatch status or not. Feedback is requested on this proposal.

We note and agree with the Regulatory Authorities statement (Section 3.6 second paragraph) that *The RAs are concerned that this may create a barrier to the repowering of existing wind farm "sites for example and the implementation of the most effective use of network assets in terms of accommodating renewable generation and may introduce perverse incentives to avoid* *necessary or useful modifications where they introduce the requirement for a new connection agreement*

Article 12 envisages loss of priority dispatch where there is a significant modification to a connection agreement. The term "significant modification" needs careful consideration, as it may lead to adverse consequences for issues such as repowering, and co-location of new renewables development with existing generation. It is our position that the interpretation of "significant modification" should not inadvertently prevent efficient forms of further renewable development where possible to do so. For example, a separately metered extension to a windfarm under an existing connection agreement should not trigger the loss of priority dispatch for the existing – most likely project financed – phase of the windfarm. Additionally, the merging of 2 units with priority dispatch should not result in the units losing priority dispatch for the sum of the MECs that had priority dispatch previously. Technical, commercial or administrative grid modifications to a project's connection agreement by IPP and/or SO should not trigger loss of priority dispatch where the following principle prevails

No "new" (i.e. with energy contracts concluded after 4 July 2019 as per our answer to Question 2, above) grid capacity will be created with priority dispatch status. Where "old" and "new" capacity shares the same connection, it must be separately dispatchable and metered to allow "old" capacity to maintain priority dispatch.

We would also like highlight that there are currently a lot of projects with modifications in train, many of which are required prior to RESS bids, therefore it would be very beneficial if this point around modifications could be clarified well ahead of the rest of the CEP decision.

Article 12 allows for generators with Priority Dispatch to voluntarily give up Priority Dispatch. Older renewables which do not have subsidies linked to the physical production of power may be quite content to experience higher levels of dispatch down, as long as it is at least cost neutral to do so. Any barriers (procedural, commercial) for a non-subsidised renewable generator should be identified and removed.

Consultation Question 12*: Do you agree with the RAs' interpretation of Article 13(5)(b) whereby downward redispatching of electricity produced from renewable energy sources or from high-efficiency cogeneration (i.e. the application of constraints and curtailment) regardless of priority dispatch status, should be minimised in the SEM? Under this interpretation, the only difference between renewable generators and HECHP eligible for priority dispatch will be how they are treated in terms of energy balancing.*

Consultation Question 14*: Do you agree with the RAs' interpretation of Article 13(7) and the view that the provision of financial compensation to firm generators subject to curtailment based on net revenues from the day-ahead market including any financial support that would have been received represents an unjustifiably high level of compensation?*

Consultation Question 15*: Which of the options on compensation for curtailment presented above do you view to be most appropriate to adopt in the SEM? Are there additional options that the RAs should consider around compensation for curtailment?*

The Clean Energy Package is a regulation, not a directive, consequently we would like to be clear that Article 13 states that generators *should* be compensated, not *may* be compensated. As such it is up to system and market operators and regulators to put in place a system and market that abides by these rules but does not make the adherence to such rules unnecessarily expensive to the end consumer.

Furthermore, the phrase "unjustifiably high" in this context does not allude to the payments made by the end consumer, rather it comes from the development of Article 13, which stated that payments *to generators* must not be unjustifiably low or u unjustifiably high. Indeed, Article 13 started out, in November 2016 stating that payments to generator must not be *unjustifiably low when compensating for lost revenue* and benefit, before "unjustifiably high" was added in December 2016. As such it does not refer to the end consumer at all and its use in this context is in direct contradiction of Article 13.

Enerco argue that generator should be compensated for all benefit when units are curtailed, whether capacity is firm or not, and all benefits under constraint where the capacity is firm. Analysis showed that for 2018 this cost €40M, which would equate to €1.03/MWh based on the all island demand forecast for that year from the 2019/20 All Island Generation Capacity Statement. For a domestic customer on a standard tariff of 15c/kWh this will be an increase of less than 0.7%.

Noting that the combined variable tariffs and charges for 2019/2020 are €25.71/MWh, this represents an increase of just 4%. In contrast there was an increase of 26% between the 2018/19 combined variable tariffs and charges and 2019/20. Consequently, this increase does not seem in any way excessive.

Furthermore, Enerco forecast that dispatch down will fall between 2020 and 2024 as more demand is added and fewer renewables are added. This is because the REFIT scheme comes to an end, before further volumes of renewables are added under RESS. Additionally, increases in SNSP increase will further reduce curtailment and, in combination with the other factors, further reduce the cost on a per MWh basis.

Whilst curtailment and constraint are forecast to increase after 2024 it does not exceed current levels until 2027, by which stage projects should fall out of ROC and REFIT support reducing costs. We would expect the concept of non-priority dispatch renewables to be implemented before the first RESS units come on, which will prevent costs rising again. SNSP will also have risen in the intervening period, further limiting costs.

Before examining the 7 options considered in the paper, we would reiterate that the Clean Energy Package is a regulation, not a directive, and so the deliverance, in full with effect from January 1st 2020, of Articles 12 & 13 is required by European law.

- Option 1 totally disregards Article 13 of the Clean Energy Package and is the worse of a series of unacceptable options
- Option 2 shows the willingness of the Regulatory Authorities to fully compensate for curtailment, though only where the capacity is firm and when the SNSP hits 100%. This appears to be an attempt to pass the responsibility for not fully implementing Article 13 on to the system operator. Whilst we are very keen to see SNSP at 100% we don't believe this approach is fair or reasonable to either participants or the system operator.
- We can understand the Regulatory Authorities concerns as regards the cost to the end customer as expressed in Option 3 and hope that this has been allayed in the analysis above. Option 3 is highly problematic as there is no clarity on what this cap would be, how it would be decided upon or how it might change in future. As such it risks kicking the can down the road and ending up with eventually confronting the end customer with the sort of costs that the Regulatory Authorities are so concerned about; essentially delivering a monster of the Regulatory Authorities own creation.
- Option 4 does provide some risk mitigation to developers in providing a defined cap above which projects would be remunerated. The question it poses is that if the

Regulatory Authorities are prepared to compensate; without an absolute cap as per Option 3 or a per MWh cap as per Option 5; then why not implement Article 13 in full in the first place?

- Option 5 is very similar to Option 3 in applying a cap, but this time on a per MWh basis instead of an absolute basis. As such it suffers from the same problems in terms of how this would be decided upon, and how it would be updated in future. This leads to the significant risk that it ends up being delayed, presenting the end customer with a large bill that would have been avoided had Article 13 been implemented in full initially
- In line with what we have noted throughout our response there is some merit in Option 6 provided that it was applied to curtailment where the capacity is both firm and non-firm and constraint where the capacity is firm. By allowing for non-priority dispatch renewables as per our answers Questions 2,3,4,6, 7 and 8, this would reduce the requirement to constrain and curtail when wind is high. It would also allow out of benefit units to be dispatched down at lower costs, further alleviating the issues. As noted previously there is a window of opportunity at present where curtailment should reduce between the end of REFIT and the start of RESS which is helped further by rising demand and increasing SNSP. The implementation of a category of non-priority dispatch renewables, as is essential to units under RESS, can then help mitigate rises in costs in future. This is done by effectively limiting the volume of renewables that will be sold ex ante when wind is very high and reducing the cost of dispatch down by taking out of benefit units first at a much lower cost.
- As regards option 7, we welcome any methods that the TSOs can implement to reduce the volume of dispatch down, now and in future. Where dispatch down does occur, we hope our responses above are clear on how this should be done to comply with the Clean Energy Package and at minimum cost to the end consumer. We strongly believe that the implementation in full of SIDC, formerly XBID, will help significantly here alongside new interconnection. In the period prior to the implementation of the market-based solution of SIDC we would encourage further TSO-TSO counter trading. Finally, we would like to praise the work the TSOs have done to increase SNSP, which has been ground-breaking and encourage raising the value still further as soon as possible.

Summary

Enerco want to help the Regulatory Authorities implement Articles 12 and 13 of the Clean Energy Package in order to

- Ensure compliance with EU law
- Retain the concept of priority dispatch – a key pillar of the SEM and I-SEM markets – for eligible units
- Ensure the provision of a clear investment signal for new renewable generation
- Ensure the implementation of Articles 12 & 13 is done in a way that minimises costs
- Reduce dispatch down for in benefit generators
- Provide a market-based solution that enhances the market signal of the balancing market
- Is as simple as possible to implement

This can be done by

- Ensuring that units with energy contracts, e.g. REFIT letters of offer or Corporate PPAs, signed prior to July 4th, 2019 alone continue to qualify for priority dispatch
- Creating a non-priority dispatch renewables category which is required to submit Commercial and Technical Offer Data
- Allowing units to opt out of priority dispatch at their discretion
- Using the existing hierarchy for dispatch down for priority dispatch units thereafter
- Compensating for curtailment for firm and non-firm capacity of priority dispatch units, for example through the Imperfections charge
- Compensating for constraining priority dispatch units for firm capacity, again, for example through the Imperfections charge
- Ensuring that such compensation is not clawed back through R factor calculations

Kind regards,

Andrew Burke.

Head of Trading, Enerco Energy