Reaction to the Public consultation

Task Force Princess Elisabeth Zone

January 2024

1 Summary

Otary wishes to thank Elia for the opportunity to respond to the Public Consultation Report (the "Report"), as well as for the extensive work that has clearly gone into preparing the Report.

Otary's response consists of this letter (which constitutes our general feedback on the predominantly non-technical aspects such as market design and balancing) and a comment sheet in excel (which provides more detailed feedback on the technical aspects). The excel lists several questions with varying order of urgency (urgent questions are labelled as such as they impact design decisions – which developers are currently taking –, and non-urgent questions which do not require a response by Elia in the context of this Report but are questions that should be answered in the Tender documentation).

Over the last 3 years, Otary has actively participated in the working group Balancing as well as the PEZ Task Force, both directly and indirectly via the Belgian Offshore Platform ("BOP"). While appreciating where proposals have been amended to take into account the feedback and discussion in the task force, most of Otary's feedback to the current Report is a restatement of feedback previously provided, as many of the concerns raised by Otary and/or BoP have not yet been considered.

We fully acknowledge that a transition to a carbon-neutral and thus predominantly renewable energy landscape in a relatively short period of time creates new challenges that require structural adjustments to the market design, as flexible and fully dispatchable generation assets will increasingly be replaced with intermittent generation assets. Such changes could lead to increased transmission and system costs. As demonstrated by several studies (e.g. the Path2050 study performed by Energyville), however, **renewable energy in general and offshore wind in particular are indispensable if we wish to achieve the energy transition *in the most cost-effective manner*.** These studies assess the total societal costs, i.e. including generation costs, complementary balancing costs, as well as the transmission and system costs. As part of the energy transition, we can expect changes in every category's respective weight in the total costs, but one should always look at the total societal cost. Otary is of the opinion that the proposed measures in the Report are designed with the aim of minimising the transmission and system costs, without sufficiently considering the impact of such a design on the total costs.

A prerequisite to achieve the lowest societal cost, is an **efficient risk allocation**. Risks should be allocated to the party best equipped to mitigate and manage that risk effectively. As society has decided that more offshore wind generation capacity is to be added to the Belgian energy system, it is important to identify any new or additional risks that come with this. The subsequent step is to then decide how these risks can – most efficiently, i.e. at the lowest cost to society – be allocated throughout the system, acknowledging that the end consumer / taxpayer will eventually bear that cost, howsoever allocated. Otary feels that although Elia, supported by DTU, has been able to identify the new risks in the Report, the proposed risk mitigation measures do not always allocate the risk to the party best suitable to carry it. Allocating risks to a party that is not the most capable of carrying it, does not only increase the cost of carry, but it also makes that cost more implicit and less transparent, and thus harder to abate or find structural solutions for.

Otary is of the opinion that the proposals put forward in the Report allocate certain risks to the OWFs, whereas they are not the most suitable party to carry them. The key underlying principle of the current tender system as decided upon by the Belgian Federal Government, a 2-sided Contract for Difference ("2s CfD"), is to limit the risk to which the OWFs are exposed to, to meteorological, technical, and operational risks, i.e. risk that are at the core of developing, constructing, and operating offshore wind farms. Others, such as market or policy risks, cannot be carried by the OWF, as they are purely external risks that the OWF cannot predict nor control. The intention of this risk allocation, guided by the tender principles prescribed in the Belgian Electricity Act of 1999 and enforced by the 2s CfD, is to ensure that the offshore wind electricity production can be brought to the market at lowest possible price.

Allocating risks to the OWFs that an OWF cannot predict, nor control goes against this principle.

Pushing inappropriate risks onto the OWFs, increases the strike price, either directly (as these risks are priced in for a duration of 20 years, at a private party's risk premium) or indirectly (if risks are conceived as too unpredictable or at least extremely hard or impossible to hedge, via decreasing tender competition).

The Report stipulates, in several instances, that the proposed measures will be used as a 'last resort' and that are probably not required in case of proper market functioning. This is however no comfort to a single-asset Special-Purpose Vehicle that has a fixed strike price, which is the intended legal and economical set-up for the OWFs in the PEZ. Without the possibility of financial upside in the business model, any additional risks, no matter how remote, is to be priced in fully from the start, as diversification or risk-transferal through ad hoc pricing cannot be used as risk mitigation strategies. **Consequently, society will bear the long-term cost implications of an incorrect risk allocation.**

This is why Otary has consistently argued that, if the proposed measures are required, the financial consequences should be compensated by Elia, and the OWFs be remunerated for their offered flexibility (which is, in essence, what all the proposals boil down to). This approach ensures that the measures will have the lowest cost to society as, rather than being priced in up-front in full and with a private party's risk premium, they are only to be paid at a lower risk premium when the risk actually materializes, and the measure is used, whilst still incentivizing investment in cheaper structural solutions (if any) to resolve the problem.

This argument is not only economically sound, but also in line with EU regulation. In this regard, Otary wishes to repeat its legal argumentation put forward in the letters by the BOP to CREG and Elia on 24 March 2022, and 6 September 2023:

> Several measures are proposed with far-reaching consequences for the wind farms. Specifically, the proposals regarding 'preventive curtailment', and 'ramping rate limitations' create far-going possibilities for Elia to intervene in the production profile of the OWFs without compensation for lost revenues.
>
> Otary wishes to, once again, draw Elia's attention to the 'redispatch' concept from EU Regulation 2019/943. Redispatching is *broadly* defined in this Regulation (Art. 2(26)) as:
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> > "*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 <u>or otherwise ensure system security</u>*".
>
> 'Redispatching' should thus be understood as any ad-hoc correction/restriction of the actual production of a specific electricity production unit for reasons related to system security, including - but not limited to - congestion management. In other words, 'redispatching' within the meaning of the Electricity Market Regulation encompasses a broader measure that is not restricted to congestion management.

This interpretation is confirmed in authoritative legal literature, as exemplified by J. PAPSCH (Deputy Head of Unit at the European Commission (DG ENER)):

> *"Thus, redispatching goes beyond the classical meaning of ordering one generation facility to ramp up and another to ramp down to relieve congestion and includes other instructions to generation facilities in the interest of maintaining system security such as limiting generation from synchronous generators."*

This reading is also evident in the legislative process. In the original proposal of the European Commission regarding the Electricity Market Regulation, the distinct concepts of 'redispatching' and 'curtailment' were consistently used side by side in Article 13 (formerly Article 12). During the trialogue negotiations, both initially separate concepts were subsequently integrated into a single definition of 'redispatching' (cf. the formulation "including curtailment" and "or ensure system security in another way" in the definition of 'redispatching').

In accordance with Article 13 of the Electricity Market Regulation, the principle is that 'redispatching' of units should be done using market-based mechanisms with financial compensation provided (pay-as-bid or pay-as-cleared). Non-market-based 'redispatching' may only be used when (i) there is no market-based alternative available; (ii) all available market-based means have already been used; (iii) the number of eligible units is too low to ensure effective competition in the area where suitable units for providing the service are located; and (iv) in the case of a risk of strategic bidding (due to the very regular and predictable occurrence of congestion).

In the case of non-market-based 'redispatching,' (i) production units for renewable energy may only be subjected to downward 'redispatching' if there are no other alternatives or if other solutions would result in significantly disproportionate costs or serious risks to network safety ('priority access'); and (ii) financial compensation is owed by the transmission system operator (to cover the loss of income).

According to our interpretation of EU Regulation 2019/943, there is no doubt that the current proposals from the Public Consultation Report are incompatible with this European Regulation.

In line with EU Regulation 2019/943, Elia should maximize efforts on market-based measures. For example, the current non-contracted mFRR scheme (i.e. the former D-bid scheme from the CIPU contracts) can be used to achieve the same goals as intended by the preventive curtailments, up-ramp restrictions, and/or cut-in coordination when deemed necessary by the grid operator. Also, the move to dynamic reserve dimensioning creates new opportunities to address additional balancing risks related to particular weather conditions (storms, fast ramps due to sudden wind changes, etc.) by contracting additional reserves for that specific timeframe.

Subsequently, further research should be conducted on how new market-based solutions can address potential issues arising from the further integration of renewable energy into the grid. For instance, a fast-ramping service could be developed to accommodate the rapid ramp-up and -down of offshore wind farms if necessary. In line with the Regulation, any non-market-based intervention by the grid operator must be compensated in accordance with European legislation.

Finally, Otary also insists that any non-market-based intervention in a production profile by Elia, declared as a "last resort" measure, should be followed by a report from Elia demonstrating to the concerned market party and the regulator that such a measure was indeed necessary to preserve the safety of the grid, and that no market-based interventions were available. This is also required by Regulation 2019/943, further emphasizing the exceptional nature of non-market-based intervention in the production profile of offshore wind energy.

Otary would like to point out that – even if the measures are remunerated – they should be used prudently, as they have the additional impact of reducing green electrons at a moment in the energy transition when we most need it. Any intervention in the injection profile of the OWFs implies less Belgian-generated Guarantees of Origin, less green electricity for our industry, and would have a direct negative impact on the contribution of the Federal State towards the achievement of the renewable energy goal set out in the national energy- and climate plan 2021-2030.

2 Technical Feedback

Otary wishes to highlight two specific technical points of feedback.

2.1 Conformity process

The Report states (page 87, section 3.8.1.2.3) that *“After the FON is granted to the PGMs and during the ongoing lifetime of the PGM installation, ELIA should have possibility to expect from the already connected generators, under reasonable conditions, to adjust their settings and even perhaps control modes to optimize the global system performance.”*

This is a statement that can have major impact on committed PGM's, making the grid conformity a ‘moving target’. At least, it should be subject to a well described procedure, taking into account any technical or operational (im)possibilities, and including a compensation mechanism based on a cost-benefit analysis.

The Report continues on page 96 (chapter 3.8.8.1 (3) (d)) with: *"Full responsibility and cost shall be beard by the asset Owner under the following conditions […]".* This statement is not acceptable and considered a red flag. After FON status has been received, such costs have to be borne by the TSO as responsible party for wider area grid stability. From experience we know that such changes as proposed parameter changes can be costly and time consuming. A CBA should be performed amongst Elia assets and other relevant Assets to look for the cheapest acceptable solution for society. The statement *“without causing a disproportionate investments”* provides little to no comfort.

2.2 Cable interface

As there are many open questions and uncertainties related to the OWF cable approach, pull-in, routing and termination towards and on the island, it is requested that Elia provides a full detailed design as part of the tender documents to create a level playing field for all candidates. Otary suggests that the PEZ Task Force is used in the coming months to continue discussions on this topic, to ensure involvement of potential candidates and to avoid the cable interface design becoming a red flag. We would expect Elia to take full responsibility of the interface design.

Uncertainties and questions are mostly related to cable corridors, future crossing, rock berm design, cable stabilisation on the scour protection, J-tube and CPS design, hang-off room design and access, availability of space and equipment, the use of culverts, thermal influences and characteristics, etc. Specific questions are provided in the comment sheet in excel as an annex to this letter.

3 Connection Requirements

3.1 Flexible connection contract

In section 2.3.1 of the Report, Elia proposes to connect the OWF in Lot 1 based on a "flexible connection contract". This implies that Elia could curtail the injection of the OWF in case of congestion on the onshore grid. These curtailments would be requested in the intra-day timeframe and would be unremunerated. Otary understands that Elia will perform a study in Q1 2024 to forecast the expected extent and frequency of these curtailments.

> To fully understand the implications of this proposal, Otary would like further clarifications:
> (i) Is it correct that such curtailments are not compensated, i.e. the perimeter of the BRP is not corrected upward to compensate for the downward curtailment, nor is the downward activation paid for at a cost-reflective tariff by Elia (as is the case with congestion-curtailments under a firm connection contract)?
> (ii) Is it correct that these curtailment requests are decision made unilaterally by Elia?
> (iii) Can Elia confirm that the study of Q1 2024 will carry no legal or contractual weight? Is Otary's understanding correct that, irrespective of the outcome of this study, there will not be a legal maximum on the amount of curtailed energy, the frequency of curtailments, nor the duration of the flexible connection contract before it is converted into a fixed connection contract?

If Otary's current understanding is correct, we would like to voice our serious concerns about the potential consequences of such an arrangement and the dramatic consequences this will have on the timely realisation of the offshore windfarms in the Princess Elisabeth zone.

Multi-billion investments crucial to Belgium's energy supply and energy transition, like offshore wind projects, necessitate a permanently guaranteed and reliable grid connection. The chosen "2-sided contract for difference" system for the new OWFs was designed to minimise (price) risks for developers, avoid windfall profits, and thus ensure that offshore wind can be developed at the lowest possible cost. A flexible connection contract contradicts these goals as it introduces volume risk (on top of the inherent resource risk which developers can quantify) and jeopardizes the cost-effectiveness of offshore wind energy for Belgian citizens and industries. **A flexible connection increases the risk profile to such an extent that it jeopardizes the financing of the developments. Moreover, from a societal perspective, it is not desirable to transfer risks associated with the construction and operation of the electricity grid to the wind farms. The grid operator is the sole and appropriate party to safeguard these risks at the lowest societal cost.**

Otary disagrees with Elia's suggestion that the *capability* based 2-sided contract-for-difference would cover all risks associated with a flexible connection contract.

- It firstly doesn't mitigate the technical risks associated with curtailments which are linked to increased fatigue and reduced asset lifetime, as well as re-start risks after a full curtailment.
- From a financial perspective, the current support mechanism doesn't mitigate all the risks. An important objective of the PEZ support-scheme is to stimulate a 'carve-out' of up to 75% of the volume, whereby electricity is sold directly to corporate (and/or cooperative) offtakers at the strike price on a pay-as-produced profile. For OWFs to, under such "PaP" contracts, mitigate this additional volume risk, the offtaker would need to absorb this risk in full, i.e.

pay for electricity that it did not receive[1] due to a curtailment decision by an external party (Elia)[2]. The allowed 3 EUR/MWh top-up for the carved-out volumes, compensates basic contractual and credit risks (inherent to contracting with a private party as opposed to the CfD), but not additional volume risks.

- a similar argument could be made for the volumes under the 2s CfD. For the OWF to mitigate this additional volume risk, it would need to be able to push this regulatory risk to the offtakers / BRPs. Even though the principle of compensation for missed revenues due to non-injected volumes is well established when it is the offtaker himself that requests the curtailment (e.g. due to portfolio balancing decisions), pushing the *regulatory* curtailment risk on offtakers, seems unrealistic as there are no 'missed revenues' as such, and will in any event, significantly limit the pool of potential offtakers (and thus candidates to the tender). The assumption made in the Report that all day-ahead revenues are automatically passed on to the OWF is incorrect, and is difficult to advocate, especially considering the (potentially very large) imbalance costs that the offtaker / BRP is to carry due to the same regulatory curtailment risk[3].
- Curtailments also implies a loss of Guarantees of Origin ("GoO"), for both the volume sold under the CfD scheme, and the carved-out volumes, and thus a loss of income for the OWF that again, is not compensated by the support mechanism. In addition, the loss of GoOs (i) make the sale of this volume of (potential) electricity to cooperative offtakers, which is a clear objective of the support scheme, impossible, (ii) negatively impacts the corporate offtakers in achieving their energy transition and (iii) negatively weigh on the contribution of the Federal State in the achievement of the renewable energy targets set out in the National Energy and Climate Plan 2021-2030.
- Lastly, the potential imbalance costs are inestimable and potentially limitless, particularly when combining the impact of a flexible connection contract with the many changes on the imbalance market that are currently ongoing, the impact of which is still unpredictable, such as (i) the connection to the Mari & Picasso platforms, potentially importing significant imbalance price volatility and unpredictability, (ii) the intention to increase the price cap for a/mFRR bids (which in turn influence the imbalance price) from 3000 EUR/MWh to 99,000 EUR/MWh; (iii) the creation of an OBZ where the imbalance price formation remains -*for now*- an academic exercise; and (iv) the further development of the onshore grid, which impacts the deployability of flexible assets, based on the 'Congestion Risk Indicator' of the area in which they are located.

Otary regrets that Elia, as a front-runner in trying to *enable* the energy transition, does not look at this issue from a broader societal perspective. A flexible connection introduces such a singular large risk that very few (to none) BRPs can mitigate. This will -at best- limit the competition in the tender to such an extent that it will drive up prices, as developers will, if they can mitigate this risk internally or place this risk in the market at all, price in all these risks (including a risk premium) in the strike price for 20 years, making the end-consumer worse off. The fact that this would be an unacceptable risk, was well understood, in the very similar context of the Stevin substation construction, when the first wave of Belgian offshore windfarms was being constructed.

[1] Even though this principle is well established when it is the offtaker himself that requests the curtailment (e.g. due to downtime of the consumption unit, or negative market prices), pushing the *regulatory* curtailment risk on offtakers, seems completely unrealistic and will, in any event, significantly limit the pool of potential offtakers (and thus candidates to the tender).

[3] We acknowledge in this regard that a well-formulated correction factor would provide certain risk mitigation for the affected BRP, however, the mitigation would only be partial as it will likely be based on market-averages (as opposed to idiosyncratic events).

In addition, the construction of Ventilus is put forward a pre-requisite for the connection of Lot 1. This is a major risk for the OWF, and construction cannot start if the timeline of the connection is not clarified. In the planning shown in Figure 21 no buffer seems to be available between the end of the construction of Ventilus and the commissioning of the first wind turbines. Ventilus seems to already be a bottleneck.

(i) Can Elia confirm that there is no buffer, or that the construction period includes a buffer?
(ii) Can Elia indicate its' underlying assumptions in this timeline; as the planning shown seems to not consider any appeal on (i) the GRUP nor on (ii) the Ventilus permit?
(iii) Will Elia, in case of appeal(s), take the risk and start construction anyway (which may be prohibited if the appeals are suspensive)?
(iv) Can a worst-case scenario timeline be shared?

We understand that there is a worry in terms of 'discrimination' in case the PEZ1 OWF is provided a fixed connection contract, as other assets have been provided a flexible connection contract based on the same congestion. As the intention of providing flexible rather than fixed connection contracts is to steer investors' decisions in terms of timing and location of their generation assets, this argument can obviously not be held against the OWF in the PEZ. Indeed, both of these choices are imposed by overarching regulatory frameworks. In addition, the very specific circumstances of the tender, which are based on a 2s CfD mechanism, barring any potential financial upside, place these assets in such a unique situation that evoking 'discrimination' does not seem relevant in the context.

Otary considers offering a fixed connection contract, based on the exceptional circumstances of the PEZ OWFs, as the best way forward. If another solution can be formulated that has the same economic and financial result, we could support such solution. We could support, for example, a solution that contains the following elements: (i) the perimeter of the BRP(s) (e.g. utility or corporate offtaker) is corrected, (ii) a remuneration equal to the strike price (plus 3 EUR – in case the volumes are part of carve-out) is foreseen for the OWF for the curtailed volumes, and (iii) the curtailed volumes that fall under the 2s CfD are excluded from the monthly CfD premium calculations, i.e. the APE should not consider these curtailed volumes as being 'available'.

4 Market design

Chapter 4 of the Public Consultation Report starts with a statement that we fully support: "*To realize offshore ambitions in the North Sea and the other European sea basins, a massive deployment of offshore infrastructure will be needed*".

These offshore ambitions, established in the Esbjerg declaration in 2022 and further strengthened in the North Sea Declaration signed in Ostend in 2023, are to install at least 120 GW of offshore wind by 2030 and 300 GW by 2050 in the North Sea. These high offshore ambitions are supported by academic research as the optimal tool to reach carbon neutrality by 2050 at the lowest system cost. The Paths2050 study performed by Energyville in 2022 clearly states that "*facilitating direct access to far offshore wind in Belgium, drastically lowers electricity and system costs from 2030 onwards*".

Elia has also recognised, in several studies (a.o. the Federal Development Plan - period 2024-2034), that **access to renewable energy from the North Sea will be crucial, considering that Belgium is and will always be structurally short in renewable energy, and thus relying on import.** Elia has been a thought leader in this regard, pushing for the integration of offshore energy into the Belgian electricity system, from within the Belgian waters as well as from the broader North Sea basin. At the same time, Elia has officially recognised that the electricity grid could be a bottleneck and delay the energy transition, against the wishes and interests of our society[4].

These statements should be translated into concrete long-term investment plans. **The project portfolio presented in the Federal Development Plan (period 2024-2034) should be more ambitiously defining a pathway to reach the offshore wind targets. A more proactive approach with anticipatory investments is necessary to keep up with the offshore development plans.**

The proposed grid design for integrating offshore wind energy in the PE zone into the Belgian grid is a hybrid solution, meaning that 3.5GW of transmission capacity from the Princess Elisabeth Island towards the Belgian coast is to be shared between 3.5GW offshore wind capacity and 1.4GW cross-zonal capacity over the Nautilus interconnector with the UK, an under-capacity of almost 30% (not taking into account plans to connect the Island to Denmark and Norway, with potentially less than equal increases of the transmission capacity to shore).

In the context of the energy transition and the (by Elia) forecasted increase in green electricity demand, we would urge to have more capacity and would think the contrary to be in comprehensible at this stage and in this context.

We consider that finding solutions for physical grid constraints is more advantageous in the long run than the current theoretical market design driven orientation. While acknowledging the significance of an appropriate market design, we remain unconvinced that it presents a more beneficial alternative to the essential grid design. Even the KARI study, used by Elia to support its Federal Development Plan[5], illustrates that faster developments of offshore wind deliver significantly greater societal benefits when compared to grid-use optimisations.

As a long-term vision and general principle to be applied across the North Sea, we do support the concept of hybrid assets, as designing transmission capacity on a 1-to-1 ratio with offshore wind *peak* capacity would lead to an over-dimensioning (and thus under-utilisation) of the grid, provided however that the generation assets or markets competing for the transmission capacity are sufficiently decorrelated. Indeed, the whole point of hybrid transmission assets is to use transmission capacity that would otherwise not be used by intermittent generation sources precisely during those moments in time when they are not producing (i.e. in the case at hand when OWFs are not producing at almost full load) to recoup the cost of the transmission assets over a larger volume of energy transported *and not to have two correlated sources compete* for the limited transmission capacity at the same time because in such case (i) the transport cost is not reduced and (ii) the LCOE of the competing assets is increased as they should recoup their investment over a smaller volume produced.

Elia seems to automatically assume that hybrid assets must be managed via an Offshore Bidding Zone (OBZ) market design. Otary is not convinced that this is the case (as certain derogations can be requested and granted, as was done for Kriegers Flak), nor are we convinced that an OBZ is under all circumstances the most optimal *societal* choice.

[4] Federal Development Plan, 2024-2035, Executive Summary, page 20

[5] Figure 3.12 in the FDP shows that stimulating offshore renewable energy is a no regret option: regardless of grid optimisation, offshore wind developments result in tens of billions of costs reductions, due to a.o. fuel savings and societal benefits related to CO2 emission reductions. The gains in optimizing the grid via hybrid projects is much smaller than the gains of the offshore wind developments themselves.

To fully understand the implications of Elia's OBZ proposal, Otary would like further clarifications:

(i) What prices is a BRP/offtaker exposed to when he purchases (on the day-ahead market) electricity in the PEZ and sells it in Belgium? Does he take the price differential between the zones? How are the TSO congestion rents calculated, and who pays for them?

(ii) Is it correct that, if the PEZ can be operated as a 'single node', the PEZ OWFs will -most likely- only be allocated 60% (2.1GW out of 3.5GW) of the transmission capacity if the day-ahead price of the UK is negative, even if the Belgian day-ahead price is positive?

(iii) Is it correct that, if the PEZ cannot be operated as a 'single node', that Elia proposes to create an OBZ covering only the Nautilus interconnector and Lot 3 of the PEZ? Does this imply that in this configuration, the Lot 3 OWF will -most likely- be allocated 0% of the transmission capacity if the UK day-ahead price is negative, even if the Belgian day-ahead price is positive, and that the OWFs in Lot 1 and Lot 2 would not be affected?

(iv) Is it correct that Elia has calculated the correlation between the offshore wind production in Southern UK and Belgium as being very high (above 75%), and that this implies that in those instances where Belgian OWF can produce at full load, that it is very likely that UK OWFs are also producing at full load, and that both will be competing for the limited transmission capacity?

(v) Do you agree that if UK is to move from zonal to nodal pricing (whereby the UK day-ahead prices will be determined on a much more local level), that favourable wind conditions in the Channel will push the (Southern) UK day-ahead price even more often to negative value?

(vi) Do you agree that it is very difficult to predict the day-ahead prices and imbalance prices that will be established in the OBZ, as they are not only driven by the congestion in the offshore grid, but -due to the Advanced Hybrid Coupling- also by the onshore grid congestion? Does this imply that the day-ahead price in the OBZ can be anything, from lower than the lowest price of the 2 connected zones (UK and Belgium) to higher than the highest price?

Many so-called benefits of OBZs have been proclaimed, where Otary does not necessarily see them as "societal benefits", as they merely represent shifting costs from one party to another – potentially at a higher price for society, rather than eliminating these costs:

- Even though the price in an OBZ will (often but not always, due to Advanced Hybrid Coupling) be aligned with the lowest-priced connected zone, it does not actually create any benefits for the consumers in the 'importing' market in terms of lower day-ahead prices as the final settlement price remains identical (i.e. the one of the marginal unit in the importing market). The consumer surplus is therefore not affected. The producer surplus for the producers in the OBZ however, is significantly reduced. This shortfall will however be compensated by higher payments under the 2-sided CfD contract and/or by a higher strike price, both at the cost of the Belgian taxpayer. So, the consumer does not have a benefit, the producer has an initial disadvantage but will ultimately be made whole at the expense of the taxpayer.
- An OBZ implies that the TSO must not make offshore wind forecasts to allocate transmission capacity explicitly, and that the forecasts made by the OWFs themselves in the context of their market bidding strategy are sufficient to allocate the capacity implicitly. From a societal point of view however, the inefficiencies that stem from forecasting errors have not disappeared. The missed opportunity of forecasting too little wind and the costs from forecasting too much wind, are still present, but are borne entirely by the OWF. Even though Otary is not against placing the forecasting responsibility with the OWF (or its offtaker or

BRP), we merely wish to highlight that this does not necessarily solve the inefficient use of capacities, as forecasting errors continue to exist, irrespective of who does the forecasting[6].

- An OBZ does avoid re-dispatching *management* costs by the TSO in one particular scenario: when there is (i) a positive imbalance price (i.e. a shortage on the Belgian market), (ii) the OWFs have excess production that they did not sell in the day-ahead timeframe (due to a forecasting error), and (iii) the transmission capacity between PEZ and Belgium is congested in the direction towards Belgium. In this situation in a Home Market design, the OWF would want to inject its excess production (in reaction to the positive imbalance price), but due to the congestion the TSO would need to redispatch this energy (a downward activation for the OWF, offset with an upward activation onshore). In this situation in an OBZ design, the imbalance price in the OBZ would not be positive, and the OWF would decide not to inject its excess energy. The TSO would not be involved in these dispatch decisions. Also in this situation, however, most costs that are proclaimed to be 'avoided' are not actually avoided but merely shifted. The imbalance payment that the TSO no longer needs to make to the OWF shifts a benefit for the OWF (producer surplus) to the TSO (which -assuming all benefits are passed on in the tariffs- creates a consumer surplus). Similarly, the re-dispatching costs that are 'avoided', reduce income from the OWF and increases income for the TSO (shifting producer surplus to consumer surplus). All these 'shifts' do not create an actual societal benefit. Indeed, the loss in producer surplus for the OWF will be compensated via other means, such as increased risk premia in the strike price, potential balancing correction factors in the support scheme, etc. which will eventually also find their way to the end-consumers. However, it seems fair to assume that the task of re-dispatching creates overhead and management costs at the TSO, and that these can be avoided in the OBZ market design, creating an actual societal benefit. One can wonder if these overhead costs are sufficiently large to justify the creation of an OBZ.

The loss of income and increased risk for the OWF in an OBZ has been recognised (both by Elia and independent academics). The most important question however remains unanswered: how will developers price in these risks and will the applied risk premium outweigh the benefits, or not? If it does, the societal benefit of the OBZ remains questionable as these may impact/halt/delay one or more PEZ concession developments.

It is a well-established principle that a rational agent, when confronted with a risk beyond their control and management capabilities, will naturally factor in a higher premium than the real expected cost associated with the given risk. This economic response is rooted in the fundamental need to safeguard one's interests in the face of uncertainty. The consequence of this pricing strategy has a broader societal implication. When a party is compelled to carry a risk it cannot effectively manage, the resultant higher premium not only serves as a financial buffer for potential losses but also reflects the economic reality that managing such risks comes at a premium. However, the long-term societal impact of this practice needs careful consideration. By aligning risks with those better positioned to manage them, we not only enhance the overall resilience of the system but also mitigate potential societal costs associated with poorly managed risks.

In this regard, Otary disagrees with Elia's suggestion that the support scheme (based on a *capability* based 2s CfD) covers all risks associated with an OBZ, for the same reasons as were elaborated upon in section 2.1:

[6] Arguing, in the OBZ context, that the OWF is obviously best placed to make its own forecasts and deal with the consequences of its errors, seems straightforward until one considers that – in the context of a storm event – Elia does not consider that the OWF is capable of doing so, and to the contrary defends that Elia's forecast is to be leading.

- It doesn't mitigate the technical risks associated with curtailments.
- The 2s CfD scheme will only be in place for 20 years, whereas the operational lifetime of modern OWF is 35 years, and other offshore generation assets are probably to be developed after that.
- An important objective of the PEZ support-scheme is to stimulate a 'carve-out' of up to 75% of the volume, whereby electricity is sold directly to corporate (and/or cooperative) offtakers under Power Purchase Agreements ("PPAs"). An OBZ would make such PPAs practically impossible. As the generation asset would be in a different price zone (i.e. the OWF in the OBZ) than the consumption asset (i.e. the corporate in the Belgian zone), the corporate would need to take the 'basis risk' which is the price differential between the day-ahead prices in both zones. Given that the OBZ prices are -at this stage- so difficult to forecast, this risk is unquantifiable and thus impossible to manage. The same argument can be made for volumes under the CfD system, where offtakers/BRPs/traders could be exposed to the price differentials between the zones, without any mitigation option.
- Any curtailments resulting from the OBZ, also imply a loss of Guarantees of Origin and thus a loss of income for the OWF that again, is not compensated by the support mechanism. The loss of GoOs make the sale of this volume of (potential) electricity to cooperative offtakers, which is a clear objective of the support scheme, impossible.
- As argued above, the potential imbalance costs are inestimable and potentially limitless. In addition, splitting the portfolio of a BRP into 2 different perimeters, reduces options of financial hedging and portfolio management.

In this context, Otary has, and continues to urge Elia to first and foremost look at the grid design and not create a structural congestion by design at this early stage in the offshore development, especially with strongly correlated import markets. In this regard, we request that Elia seriously considers increasing the already foreseen HVDC link capacity from 1.4 GW to 2 GW, which has become the new industry standard, and/or already construct the additional HVDC link from the Island to Belgium that is foreseen for Triton (and thus not wait for the full Triton connection to be constructed to already open up additional capacity from the Island).

Secondly, we would like to **reiterate that the risks of the OBZ remain too vague and abstract for developers to assess correctly at this stage.** The OBZ is shrouded in political uncertainty ('Will the UK return to the European single implicit price coupling?'), technological uncertainty ('Will DC circuit breakers be commercially available in the near future?'), and regulatory uncertainty ('How will the European imbalance price formation evolve? Will the UK implement nodal pricing? What impact will the advance hybrid coupling have?'). Elia cannot answer all these questions, understandably so. But developers are requested to take a view on these matters, assess the risks, and express them in monetary terms to be reflected in the strike price by the end of next year. All these risks will be factored into the strike price (if developers are able to price the risk at all) and will find their way to the end-consumers or taxpayers.

Thirdly, an OBZ design makes corporate and cooperative PPAs practically impossible, even though this is a key ambition of the support scheme. The OBZ would thus impede the Belgian industry to directly access green electricity under a stable, long-term, fixed-price contract.

To provide some comfort to developers at this stage, without requesting perfect foresight from Elia, nor a 20-year regulatory stand-still, **Otary proposes to proceed with a Home Market Design, and that the guarantee is provided that an OBZ will only be implemented in a context in which the risks appear manageable for all market actors, and when the business case of the OWF can be secured.** Otary therefore requests that the OBZ will only be further discussed when the preferred long-term scenario as prescribed by Elia in the Report has become reality, i.e. when the following conditions are fulfilled:

(i) The UK returns to the European single implicit price coupling; and
(ii) The Princess Elisabeth Zone can be operated as a single node; and
(iii) Nautilus and Triton have gone live and are interconnected on the PE Island, and an increase in transmission capacity between the PE Island and Belgium is in place for at least the total capacity of the Triton link.

When these preconditions are satisfied, a thorough analysis of the impact and mitigating measures to implement an OBZ can be performed. It should be noted that even if all these conditions are fulfilled, the OWF business case has been awarded and financed based on a different market set-up (and therefore different risks), implying that a need for changes in the support scheme, or other mitigating measures could be expected.

5 Balancing design

5.1 Mitigation measures for storm and ramping events

Otary recognises that increasing the share of intermittent renewable energy in general, and offshore wind in particular, as it is a large concentrated and correlated generation source, poses certain challenges and requires the implementation of new market designs, new regulations, as well as the development of new types of assets to ensure a successful integration of these renewables into the energy system, and thus a successful energy transition.

In the context of the societal and political choices that Belgium and Europe have made, all market actors should play their role and take their responsibility in making the energy transition happen. Elia, as a thought leader in this regard, has on multiple occasions argued that various aspects will be required to ensure a successful transition: strong ambitions with regards to renewable energy capacity, a reliable national and European grid, a market design stimulating investments in storage and flexible assets, R&D in new technologies, etc. Otary fully subscribes to these statements.

Otary supports several initiatives contributing to a net-zero society: the Consumer-Centric Market Design, further European market integration, the build-out of a strong and reliable grid, digitalisation, increased freedom for market participants (e.g. multiple BRP's on 1 access point, relaxing of the balancing requirements in day-ahead, etc.), … Embedded within this wider context, Otary could also support additional asset-related regulations, if (i) proportionate to the risk, (ii) based on a societal cost-benefit analysis, (iii) respecting the basic role-division of the different market participants, and (iv) correctly remunerated, as per the European legislation.

As a general concern, Otary is not convinced that all the proposed mitigation measures fulfil these criteria. We feel that Elia has been overly conservative when designing the different mitigation measures and should better assess these measures from a *societal* cost perspective.

Firstly, the measures interfere with the clear distinction between BRPs and their responsibility, and the TSO and its responsibility. A BRP has a best-effort obligation to balance its portfolio, including in case of storm events, and is incentivised to do so through the imbalance price. However, BRPs cannot be held responsible for managing system risks. If appropriate incentives are present for BRPs to balance their portfolio, *and we feel that they are*, and sufficient (market) means are available to do so, the residual risks for grid security and stability must be borne by Elia. Many of the proposed mitigation measures push this residual responsibility, and the related costs, back to the (offshore) BRPs.

Secondly, the fact that certain costs would be borne by Elia, does not imply that the societal costs are higher, nor does the opposite, namely the fact that certain costs are borne by private market players, imply that these costs do not exist and do not find their way to the end-consumer. Indeed, any rational market player will seek to recoup its unavoidable costs. From a societal cost-benefit point of view, certain risks should be borne by the TSO, as the TSO is best placed to mitigate these risks in a cost-effective manner. Transferring costs from Elia to BRPs does not make the cost disappear. To the contrary, certain risks may be more costly to manage at a more micro level than at system level. Moreover, pushing such costs only to BRPs who actually take their responsibility in the energy transition by investing in renewable assets, creates the perverse effect of discouraging such crucial investments.

We understand from the DTU study as well as the discussions in the task force, that the risk for grid instability is not necessarily caused by the ramping or storm events themselves, but by their unpredictability.

Several evolutions will inevitably decrease this underlying problem over time:

- As the electricity market is becoming increasingly more flexible and fast-responding, this will facilitate the integration of additional renewable energy sources;
- As forecasting models improve, and BRPs gain experience with the offshore environment, the variability will be better forecasted, so that the market can adequately react.

Otary therefore urges Elia not to override a proven and well-functioning market design where responsibilities and costs are allocated where they belong by overregulating and imposing long-term strict technical measures on one single technology (and then only for its offshore application) without taking into account (i) the level playing field between technologies, (ii) the inherent trends in the electricity market that would inevitably decrease the problem, and (iii) the fact that the imposed regulation will influence the tender-prices for the full duration of the concession, i.e. creating a long-term cost impact for a potentially only short-term problem, whilst, at the same time, removing market signals that should precisely promote the market evolution to cope with renewables integration.

Chapter 5.5 of the Report elaborates on how Elia's reserve requirements are calculated, and intents to clarify the impact of the integration of variable renewable generation on reserve capacity and balancing capacity procurements. As a general consequence of the unavoidable forecast error of variable generation, the reserve capacity needs are expected to increase, a trend which will be partly offset by the increase in flexibility in the system.

In relation to storm and ramping risks, Elia seems to want to minimise its impact on the reserve requirements, by choosing the alternative of pushing the risk on the asset. Whether or not this is the best approach, from a societal cost-benefit perspective, is not proven.

After the lengthy debates in the task forces, Otary agrees that a storm should not be a dimensioning incident, as this would imply a constant increase in reserves (a long-term cost) to cover a periodical storm-risk (a short-term benefit). The move to dynamic reserve dimensioning (whereby FRR needs are determined day-ahead with a resolution of 4 hours) however, does provide the correct framework to account for a forecasted storm in the reserve dimensioning within the appropriate timeframe. Our understanding is that a storm would be labelled as an 'exceptional event', and that this would trigger additional balancing reservations. We wish to better understand how this mechanism would work exactly, and how it would interact with the proposed mitigation measures, i.e. if Elia has procured additional fast upward reserves in the 4h-block in which the start of the storm is forecasted, would Elia then still have the right to preventively curtail the OWFs that -according to Elia- do not have sufficient mitigating measures? If so, there might be a double-up of conservatism, whereby -even if the system would only need the flexible capacity once-, there would be competition to secure this flexibility (from the individual OWF to 'prove' to Elia that they have sufficient mitigation measures, as well as from Elia itself, on the reserves market), merely driving up the price for everybody involved whereas no actual risk mitigation occurs.

From an economic perspective, Otary challenges the notion that a TSO covering residual imbalances necessarily implies a socialization and/or an increase of costs. Such a statement firstly ignores the benefits in cost efficiency and risk management at a larger scale, as well as the fact that the costs of the reserves are borne by the party creating the imbalance, through the imbalance price. Indeed, on the aggregate level, residual imbalances that were impossible to trade away before real-time, can level each other out, reducing balancing costs to zero (whereas they could have been very high had every individual party attempted to be in balance, at any cost). Additionally, if a TSO can balance cheaper than individual BRPs can (because it does so on a bigger scale, potentially based on longer-term contracts, and/or better credit risk), this actually creates a societal *benefit* rather than a cost. Otary encourages a nuanced understanding, rejecting the simplistic view of increased reserves as an economic burden.

5.1.1 High Wind Speed capabilities

The market is fast implementing High Wind Speed technologies, and this technology is becoming a customary feature for most turbine manufacturers. However, there are important differences in the workings of such technology, depending on both the manufacturer and the WTG model.

Otary recognises the benefits of High Wind Speed technologies in storm conditions, both for the developer and the end-user, as well as the grid operator, and we therefore are not opposed to an enforcement of such technologies via the Federal Grid Code.

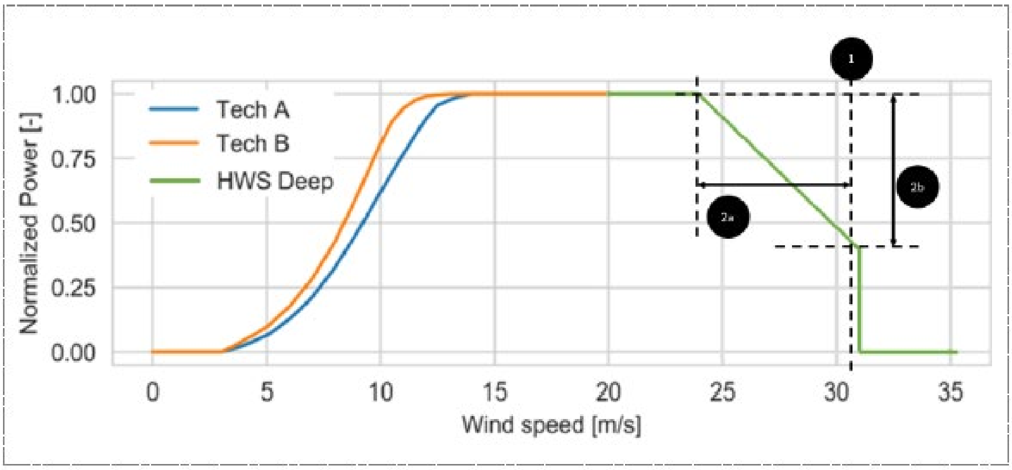
To avoid that a requirement for a certain technology or set of specifications, would disproportionately influence the turbine-decision and thus drive-up prices, **we request that the specifications are kept sufficiently broad, and focus on the downward slope of the power curve but do not prescribe the exact cut-off wind speed.** Allowing a mixture in the PEZ of both 'moderate' and 'deep' HWS (as defined in the Public Consultation Report) should actually rather be seen as a benefit from a grid perspective, as it smoothens how the total PEZ capacity reacts in case of a storm, further spreading out – in time – a potential full shut-down.

We therefore suggest that the technical requirements should be limited to the prescription of the downward slope, as follows (section 5.7.1.1 of the Report), but without the specification of the minimal sudden cut-off speed[7] (1 in the figure below) :

> *A sudden cut-off with an instantaneous reduction of the wind power injection from full capacity to 0 MW will not be accepted and a minimum slope of power decrease will be requested with:*
>
> *a. gradual power decrease starting at an average wind speed at least 5m/sec below the sudden cut-out average wind speed (2a in the figure below);*

[7] Note that the most recent OWF in the Eastern Zone (SeaMade) has the 'Moderate HWT' technology, and not the 'Deep HWT' as is suggested in the Public Consultation Report.

b. *gradual decrease of power must be guaranteed until a Nominal Power of at least 0.5 before sudden cut-out occurs (2b in the figure below).*



5.1.2 Preventive curtailments

Otary disagrees with the 'preventive curtailments' measure as proposed by Elia in the Report.

It is the obligation of the BRP to balance its portfolio; a BRP will thus organise, on a best effort basis, the management of a predictable storm event. The BRP is incentivised to do so, via its exposure to the imbalance price, plus the risk of additional liabilities as foreseen in the regulatory framework.

Apparently, Elia is not convinced that BRPs are sufficiently incentivised to organise themselves. Preventive curtailments are proposed by Elia to force BRPs to manage their portfolio in the intra-day timeframe, based on Elia's forecast of the storm, rather than their own. This is clearly an interventionist measure, which goes against the basic principle that a BRP is allowed to balance its portfolio with the means and strategy of its own choosing.

While it's the obligation of the BRP to balance its portfolio, it is the role of the TSO to ensure the security and stability of the grid. In this context, Otary clearly recognizes the right of the TSO to interfere in market functioning to safeguard the grid. Therefore, if Elia would identify a system risk related to a storm event, it should intervene to ensure the security and stability of the grid using the tools it has at its disposal. At its own discretion Elia can always, proactively or in real-time, redispatch (i.e. activate decremental and incremental bids with perimeter correction to shift injection) to mitigate system risks. This is an effective measure – based on clear, transparent, and non-discriminatory rules – that has no impact on market functioning and fully respects the role of the BRP and ensures proper transparency and accountability on the part of the TSO for overruling the BRPs' own portfolio management.

Indeed, the proposed measure is triggered based on Elia's forecasting tool. The measure would clearly have a financial impact for the BRP, even though it is not proven that Elia's forecasting tool is superior to the tool from the individual BRPs, nor will Elia take any accountability with respect to the accuracy of its tool.

To fully understand the implications of Elia's proposal, Otary would like further clarifications:

(i) Can Elia confirm that its offshore wind forecasting tool only uses weather forecasts and technical assumptions (power curves and assets' availability) as inputs, and that the forecast does not take other aspects into account such as implicit or explicit balancing actions, congestion limitations, etc.?
(ii) Can Elia guarantee that it will not change the underlying methodology of its forecasting tool, without approval of the Working Group Balancing?
(iii) In particular, can you confirm that the tool currently does not take Elia's estimation of implicit balancing by the OWFs into account in its day-ahead (11AM) forecast, and that it is not the intention to do so in the future, nor to include Elia's forecasted impact of any of the proposed measures in the future?

Otary further wonders why the current storm procedure does not provide sufficient options for Elia to manage the identified risks?

The current storm procedure respects the different roles and responsibilities of the market participants:

- BRPs are allowed to self-manage their portfolio based on their internal tools, but bear the consequences via their exposure to the imbalance price;
- Elia has the option to pro-actively activate slow-start units (so that they run at a minimal power and can participate in the balancing merit orders) to increase the balancing means, if Elia is of the opinion that there is an uncovered / residual risk. The upward activation of these slow-start units is compensated by a downward activation as per the relevant merit order, i.e. at the lowest cost possible.

If Elia's forecast was more accurate, the full balancing merit order would be activated, the (high) costs of which are reflected in the imbalance price and borne by the BRPs whose forecasts were incorrect. If the BRP's forecast was more accurate, the pro-active action of Elia would not have been required, and the BRP would – quite logically – not bear that cost.

The newly proposed mitigation measure is intended to be *additional to* the existing procedure, but it is unclear which additional benefit this measure brings in terms of system security. If Elia forecasts a residual balancing risks due to a storm event (i.e. a lack of sufficient upward reserves to balance an uncovered ramp-down of offshore wind), it will preventively curtail those OWFs without remuneration. Can Elia elaborate on how this creates additional balancing means? We rather feel that this will remove balancing capacity as this capacity will be preventively dispatched, and thus unavailable to deliver other services and cope with other events on the physical market.

Indeed, the curtailed OWF will need to source upward capacity in the intra-day timeframe. If such upward capacity is still available in intra-day, that implies that there was sufficient flexibility available in the system, and it is very likely that this capacity would have also been available in the balancing timeframe (either available to Elia as non-contracted a/mFRR bids, or available for implicit balancing based on the imbalance price incentive). If no such upward capacity is available in the intra-day timeframe, that implies that there isn't enough flexibility in the system, and that it thus becomes practically impossible for the BRP to manage its imbalance; an imbalance that was actively created by Elia. The line between a strong incentive and a mere financial punishment seems to be crossed in this context.

If there is insufficient flexibility in the system, we suggest focussing on interventions and measures such as ensuring that the imbalance price is a clear pricing signal on which several technologies can respond, opening the market to smaller-scale flexibility, ensuring sufficient slow-start units remain available in the system for times of need, etc. Elia has in the past argued that the volume of slow start-units that could be activated on the day of the storm might not be sufficient. The OWFs are however not the cause of insufficient flexibility in the system and should not pay the price for this via preventive curtailment. This would go against the EU and national legal frameworks. As several technologies that will form an integral part of the generation asset base in a net-zero society are fast-ramping technologies (solar, onshore wind, batteries, etc.), it makes sense to look at more structural measures to deal with the identified risks.

We would also like to point towards the opportunities offered by the dynamic reserve dimensioning in this regard; in case of a forecasted storm, Elia could reserve additional reserves in the relevant 4h blocks in which the start of the storm is forecasted.

Additionally, the measure is clearly interventionist as BRPs are no longer allowed to rely on their own internal balancing and forecasting tools (while obviously facing the consequences if they are wrong) but are forced to align their portfolio on Elia's forecast. Where the original storm procedure ensures that Elia creates additional balancing means (by allowing slow-start units to complement the a/mFRR merit order), the preventive curtailments measure appears to merely financially punish BRPs with a diverging view.

The Report also proposes to extent the preventive curtailment measures beyond storm events, to cover downward ramping events. The Report stipulates the following (bottom page 223): *"The success of the measure for this type of events nevertheless depends on the feasibility of accurate forecast of such ramping events and uncertainty still exists if the measure can adequately cover ramping events. It is therefore not excluded that the limited predictability may require complementary solutions such as for instance the procurement of additional upward balancing capacity."*

Otary would like to firstly point out that the Report does not actually define 'ramping events'. A workable definition should have both a capacity element (amount of MW) and a timing aspect (within a certain timeframe). Developing potential measures, that have an important cost impact on OWFs, to mitigate 'events' that remain undefined, creates significant regulatory uncertainty. Without a clear view on what exactly a measure intents to mitigate, one can from a methodological standpoint, question the research that has gone into trying to identify several potential measures and the comparison of their respective net benefits.

Otary would further like to point that, indeed, forecasting ramping events is extremely difficult, if not impossible. The quote above therefore contains a circular reference by stating that *the success of the measure* depends on the extent to which ramps can be forecasted. If ramping events could be better forecasted, the measure itself would not be 'more successful', it would be redundant, as BRPs would resolve it proactively in line with their balancing obligation. In essence, the proposed 'solution' inadvertently mirrors the conundrum it seeks to remedy, akin to asserting that a cure would be more efficient without the presence of the underlying disease. This paradox underscores the inherent challenge posed by the unpredictability of fast ramping events. Otary urges a comprehensive examination of these intricacies in ongoing deliberations to ensure a robust and effective resolution.

In addition, Elia is not willing to remunerate such preventive curtailments, putting an unacceptable financial burden on the BRPs, and going against European regulation in this regard. These costs will be pushed through to the offshore developers, merely increasing the cost of development, which, either directly or indirectly, will find its way to the end-consumer.

In summary, Otary strongly opposes the proposed measure of unremunerated preventive curtailments in case of storm or ramping events. Otary feels this measure does not respect the fundamental roles of the TSO and the BRP, nor does it address the actual underlying issue of limited sufficiently fast flexibility in the system.

If Elia is of the opinion that the current balancing market design cannot properly mitigate the risks emanating from the onset of a storm, it has the obligation, pursuant to the Electricity Market Regulation, to firstly assess market-based mechanisms. In this regard, Otary requests Elia to look into (i) ensuring there are sufficient slow-start units to be activated in line with the existing storm procedure, and/or (ii) the opportunities posed by dynamic reserve dimensioning, which allow for a forecasted storm event to be taken into account in the reserve dimensioning only for the relevant timeframes.

Otary does not object to including the technology-specific requirement of being able to receive and act upon preventive curtailments requests in the regulatory framework, on the condition that this measure (i) is remunerated, as per EU Regulation 2019/943, (ii) is used as a last-resort, and (iii) is subject to a reporting obligation from Elia to the CREG, elaborating on the exceptional circumstances that triggered the use of the measure.

The remuneration can be based on the well-established remuneration principles for mFRR services: (i) a correction in the balancing perimeter, and (ii) a quoted price (EUR/MWh), based on the standard restrictions on this price (e.g. a BSP cannot manipulate the market, etc.).

5.1.3 Ramping Rate limitation

Otary disagrees with the 'ramping rate limitation' measure as proposed by Elia in the Report, for many of the same reasons as to why we disagree with the 'preventive curtailment' measure.

Firstly, it goes against the basic role division between a BRP and the TSO, whereby the BRP should be free to manage his portfolio as he sees fit, as long as the 'prudent person' principle ("*goede huisvader principe"*) is respected. Secondly, all the market mechanisms to ensure correct behaviour already exist, as do the required regulatory mechanisms to intervene in the remote cases of remaining system risk. As also hypothesised by Elia in the Report, if the system is (very) long, the imbalance price will most likely be (very) negative, and OWFs not only not have an incentive to ramp up slowly, but even have an incentive to actively curtail their production, i.e. ramp down as much as possible. In the rare occasions where the OWFs would not, through implicit balancing, react to these market signals, Elia can request their downward activation using the mFRR product.

Offshore wind in Belgium has already proven to be able to play its role in the market by offering downward flexibility at reasonable prices, both as aFRR and mFRR products. The technology's responsiveness to market signals is only expected to improve, as older technologies are gradually replaced (through repowering), and regulatory hurdles (such as injection-based support systems) are reformed.

Offshore wind will continue to offer flexibility and play its role in the fast-changing market. Otary however strongly opposes the notion that offshore wind should, as the only targeted technology, face technical limitation in case of system imbalances that were not caused by offshore wind to begin with.

The Report fails to explain how the ramping rate limitation is proportionate or non-discriminatory, and in particular fails to explain why this service that offshore wind would offer to the market, would remain unremunerated. The Report merely quantifies that, if offshore wind is subjected to such limitation, there would be less system issues. The same would obviously hold, if nuclear generation capacity, or onshore solar generation, would automatically shut down as soon as system imbalance hits [500] MW, or if all demand side management would be automatically activated upwards.

As stated above, if Elia is of the opinion that the current balancing market design cannot properly mitigate risks, it has the obligation, pursuant to the Electricity Market Regulation, to firstly assess market-based mechanisms. **In this regard, Otary refers to the fact that, via the obligatory offering of mFRR by offshore wind, Elia will always have the available downward capacity that offshore wind can offer. The ramping rate limitation does, in no way, increase the flexibility available in the market, it merely makes that same flexibility available to Elia free-of-charge (but, for the avoidance of doubt, therefore not free for society).**

Similar to our standpoint with respect to the preventive curtailments, Otary does not – in principle – object to including the technology-specific requirement of being able to limit its ramping rate based on a system indicator in the regulatory framework, on the condition that this measure (i) is remunerated, as per EU Regulation 2019/943, (ii) is used as a last-resort, (iii) is applicable to all technologies technically able to participate in this additional 'ramping rate service', and (iv) is subject to a reporting obligation from Elia to the CREG, elaborating on the exceptional circumstances that triggered the use of the measure.

In the context of the ramping rate limitation, we propose the following product design:

- The activation of ramping rate limitations would be triggered only when offshore wind generation exceeds 20% of the Installed Capacity (per OWF). This approach aims to mitigate the technological costs of prolonged and deep curtailments. It is worth noting that, if economically viable, the OWF retains the option to limit its ramp-up based on the imbalance price.
- The automatic activation of ramping rate limitations would occur when the System Imbalance surpasses +500 MW. We recognize the potential reduction in workload afforded by an automatic mechanism and can support for its implementation in this specific scenario.
- Given the automatic nature of the system, upfront knowledge of the price is essential for both parties. Therefore, we propose the application of the congestion pricing (using a cost-based approach), rather than the balancing pricing, to ramping rate limitation curtailments. These curtailments would be measured using the same methodology as aFRR curtailments, involving a comparison of the Available Power Estimate with a mathematically calculated baseline that accounts for the ramping rate limitation. This calculation leads to the determination of a variable termed "ramping_reserve_requested."
- The BRP's perimeter will be corrected based on the calculated "ramping_reserve_requested" volume.
- These curtailed volumes should be excluded from the monthly CfD premium calculation, i.e. the APE should not consider these curtailed volumes as being 'available'.

We are happy to continue to discuss these proposals in the PEZ Task Force.

5.1.4 Preventive Cap

The preventive cap is introduced to prevent "overloading of the HVDC system". This clearly categorizes the real-time operational preventive cap as a non-market based redispatching and as such is to be remunerated in accordance with EU Electricity Market Regulation. The specifics of this remuneration, are to be discussed in the PEZ Task Force.

> To fully understand the implications of Elia's proposal, Otary would like further clarifications:
> (i) Can Elia clarify whether this preventive cap will be applicable to Lot 1, 2, or 3?
> (ii) From the task force, Otary understood that the preventive cap will not be required in case of available transmission capacity, or when there is "operating margin". As the intention of the grid design (with hybrid assets) is to ensure that the transmission capacity is used optimally at all times, and any lack of wind production in the PEZ will be compensated with additional import from or export to the UK, can Elia outline in which situations there will be an 'operating margin'? Will this only be in case of full import from the UK (1.4 GW), and when the OWF are producing at less than 60% capacity factor (i.e. less than the remaining 2.1 GW of available transmission capacity to Belgium)?

Furthermore, and as mentioned in relation to the structural congestion between the energy island and the Belgian onshore grid, 2 GW is the industry standard for HVDC connections, instead of the 1.4 GW referenced throughout the Report. There is therefore ample opportunity to avoid, or at the very least reduce, the need for this preventive cap and to possibly rely on the existing measures for congestion management.

We request Elia to further elaborate on the preventive cap and the operating margin, as these concepts and their potential impact are not yet entirely clear to us.