



# **Support on the use of congestion revenues for Offshore Renewable Energy Projects connected to more than one market**

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## **EXECUTIVE SUMMARY**

In order to achieve the 2050 and intermediary targets of the European Green Deal, a massive deployment of renewable energy is needed. Given its significant potential, offshore renewable energy has a key role to play in achieving such targets. The European Commission therefore has high ambitions in its further development. This led to the definition in 2020 of the EU Strategy on Offshore Renewable Energy. In particular, hybrid offshore projects - which connect more than one bidding zone – can bring substantial socio-economic welfare improvements by allowing an increase in market integration, a more coordinated investment planning and a decrease in system costs. Besides, it also brings other benefits such as a lower need for additional connection points and a more limited impact on the environment than radial connections. From an economic and regulatory perspective, in particular, it is generally agreed that dedicated offshore bidding zones (OBZs) are the most efficient way to integrate hybrid projects in the European electricity system. As a matter of fact, offshore bidding zones ensure a more efficient dispatch and pricing of energy and transmission, given the more granular representation of the grid in the market clearing.

On the other hand, hybrid systems with dedicated offshore bidding zones are a new way of integrating large offshore projects in Europe that may lead to financial asymmetries. This effect is highly dependent on grid topology and, although the hybrid system should be designed in such a way that the entire energy production can structurally be exported onshore, it may not always be the case. Where there is congestion, offshore bidding zones may reduce market prices and revenues received by offshore generators when compared to a traditional integration into an existing onshore bidding zone. In comparison to the latter, offshore bidding zones tend to “shift” part of the value of the hybrid project from the offshore generator to the owner of the transmission network (Transmission System Operators, TSOs) in the form of network congestion incomes. This is a natural outcome of the market coupling and welfare improving, giving transparent price signals to both TSOs on the need for additional transmission capacities, as well as to generation and demand project developers to develop projects accordingly. As such, offshore bidding zones ultimately benefit to EU energy businesses and consumers collectively,, since the overall social welfare is maximised. While the benefits are mostly system-wide, the economic risk can concentrate further on offshore generators (e.g. wind farms) due to specific market dynamics at play. This could become a deterrent for investment and ultimately adversely affect the offshore renewable energy targets. This report assesses market-based options to alleviate this potential risk for the business case of offshore renewable developers when OBZs are established.

Congestion income represents the revenue collected by TSOs from the allocation of cross-zonal transmission capacity over relevant market timeframes. It remunerates cross-zonal transmission capacity for the service it delivers in terms of system-wide generation cost reductions. A more granular representation of the grid, and dedicated OBZs in particular, values transmission and generation capacity more efficiently. We argue that the alternative distribution of the hybrid project’s value among offshore windfarms and TSOs does not justify in itself the implementation of a reallocation methodology in favor of newly built generation assets (wind farms). Only investments already made in an existing BZ could legitimately advocate for a “make-good” compensation if they were to transition into an independent OBZ. Still, dedicated offshore bidding zones clearly induce shifts in the risk

profile faced by each stakeholder when compared to an integration in existing (onshore) bidding zones. Smaller bidding zones (incl. OBZs) increase the need for hedging transmission risk on forward markets and liquidity is an issue if market participants are not provided with adequate tools. We concluded in an earlier report (Laur & Küpper, 2021) that this issue can be addressed by reviewing the Forward Capacity Allocation Guideline, in view of increasing liquidity in the trading of Financial Transmission Rights (FTRs). In the present report, we argue that OBZs also accentuate the economic impact of the transmission capacity availability for offshore generators. The strong correlation between the offshore bidding zone dynamics, the grid topology and the level of transmission capacity is probably their most distinguishing aspect. Reduced availability of transmission capacity can be the result of (1) coordination issues between grid and generation planning (the extension of the transmission grid is lagging behind), (2) force majeure & emergency situations, (3) line maintenances and upgrades as well as (4) reduced capacity allocated to the market. To address situation (1), ensuring tight coordination and establishing the offshore bidding zones only when visibility on the entire offshore grid expectations exists is probably the best solution. Situations (2) and (3) are typically addressed in the access rules of the connection contracts with the TSOs. Situation (4) refers to instances when the operational transmission capacity allocated to the market is reduced ("derated") by TSOs to ensure system reliability. Derating hybrid cross-zonal transmission capacity clearly creates a risk for offshore wind farms that is currently not addressed. Such actions – in the case of offshore bidding zones – cannot be justified by internal (intra-zonal) congestion as there is none by definition. Hence, if deratings are applied on hybrid links, it is therefore to account for the effect of internal congestion elsewhere in the system. These "operational deratings" expose offshore generators located in a dedicated OBZ to specific transmission risks that may justify the implementation of measures to mitigate it.

Past studies such as (THEMA Consulting Group, 2020) or (ENTSO-E, 2021) have already discussed a number of congestion income (CI) redistribution options. While they did not specifically focus on the operational deratings risk, the options could be used to address it. In general, since the very concept of CI redistribution is not foreseen in the current legal framework, it is clear that these options all require different degrees of regulatory changes. While some were found to require only modest integration efforts, others appeared in direct contradiction of fundamental EU principles and were found as such quite unrealistic. In this report, we studied therefore two of these options in more detail:

1. "CI-FTR": Financial Transmission Rights (FTRs) allow participants to hedge the locational risk between two neighboring bidding zones and in a specific direction. TSOs normally auction these contracts forward and remunerate the holders at the price spread when the latter is unfavorable. The free allocation of FTRs to hybrid projects would shift the associated congestion income from TSOs to offshore generators. This is what we propose under the "CI-FTR" appellation. More concretely, one could consider a pre-allocation round where some FTRs would first be reserved to offshore generators before auctioning the leftover to other market participants. This ex-ante distribution could possibly be part of the competitive tender whereby connection contracts are awarded (at investment decision level).
2. "CI-CfD": Traditionally, Contracts for Difference (CfDs) are signed through a tenderized process between governmental bodies and certain categories of generators. They enable the winners to secure a fixed "strike" price for their production that is agreed by regulators or Member States, thereby removing any price uncertainty. However, the CfD contract could be reconditioned to introduce the onshore (domestic) market price as a variable strike. With the TSO as counterparty, the design of this new "CI-CfD" would permit the long-term allocation of the zonal price spread for every unit of energy produced.

Both options have in common that their financial value extends beyond simply addressing the identified problem of operational deratings. Offshore generators will receive compensation every time the OBZ price is below the domestic onshore (reference one), whether transmission capacity is derated or not. Therefore, CI-FTRs and CI-CfDs typically

overcompensate offshore generators for the specific transmission risk they face. This is why we conceptualized a third option in the course of this report:

3. "TAG": the Transmission Access Guarantee (TAG) intends instead to tackle the risk at the source, by defining a compensation paid by the TSO to offshore generators if the latter face transmission capacity reductions as a result of operational deratings. **The hybrid system should typically be designed in such a way that the entire wind production can structurally be exported onshore.** The TAG would set a target to ensure that the true export capabilities of the offshore generator on the market is always greater or equal than the total installed net wind capacity. In instances when this target cannot be achieved cost-effectively and for congestion management reasons, a compensation mechanism would then be set up for the offshore generator to recover the missed-out revenues it would have collected in a reference market. The compensation would correspond to

*TAG compensation = Max(reference bidding zone price – OBZ price, 0) x total offshore generation available.*

The reference bidding zone could be related to the terminal of the hybrid asset in the country of the Exclusive Economic Zone. This compensation would be paid by the TSOs responsible for the restricting network elements. As such, TSOs have the incentive to only limit transmission capacity when the associated system benefits outweigh the offshore generators' opportunity costs. The described TAG rule would be suitable for all network representations (NTC, Flow-Based including possibly the Advanced Hybrid Coupling approach).

The comparison of these three options leads to the following conclusions and recommendations:

### **Addressing the identified problem**

*Options 1 & 2:* The allocation of CI-FTR or CI-CfD is not directly targeted at the identified problem (operational capacity reductions) and leads to overcompensations to offshore generation. This creates issues at several levels:

- The mechanisms are difficult to scale-up, since increasing amounts of CI have to be shifted from TSOs to offshore generators if more hybrid projects are implemented, which may endanger revenue adequacy of regional TSOs. This may also provide disincentives to the TSOs to propose hybrid infrastructure projects (and to ENTSO-E in the Strategic offshore network development plans);
- Eligibility to the mechanisms might be an issue: assets located in "smaller" onshore bidding zones could be discriminated and may claim to be treated in the same way and defining eligibility criteria may therefore prove complex;
- The mechanisms represent a non-transparent way of supporting offshore renewable energy. There is no clear reason why CI should be used to support offshore renewable energy. Traditional, direct support mechanisms provide information on the support cost more transparently;
- With more hybrid projects, TSOs will have to shift increasing amounts of CI that will have to be compensated by higher grid tariffs. The national discussion of increasing grid tariffs tends to be challenging, as so it can be having support schemes for renewables in place. With a shift that has impacts on tariffs instead of state aid, the public support is moved from taxpayers' to consumers' contributions and may result in a delayed investment on the necessary offshore grids. Therefore, any possible shifts of congestion income would need to be proportional and limited to the barriers identified in this report. Moreover, **a large-scale deployment of CI-FTRs or CI-**



**CfDs will tend to increase the relative importance of grid charges in the final electricity tariff**, thus rendering demand side flexibility (where only the commodity price can be recovered) less attractive.

The mechanisms should be phased out if smaller BZs are defined or if grids are reinforced in the future. Operational deratings should occur less and less. However, the proposed contracts according to Options 1 and 2 do not phase-out by design and it might be difficult to abolish them as it shifts potentially large amounts of revenues to offshore generators. *Option 3*: TAGs, on the other hand, are directly targeted at the identified problem and minimize the issues described above.

*All Options*: None of the mechanisms guarantee hybrid projects to realize a positive business case, which was never the primary objective of this work. As mentioned by stakeholders during workshops organized in the course of this work, the proposed options might still need to be complemented with a direct support mechanism or PPAs to unlock investment.

### **Operational aspects**

*Option 1*: The amount of issued FTRs is currently restricted by the physical capacity of the interconnector. Thus, issues arise when/if the capacity of the offshore wind farm exceeds the capacity of the cable in the direction of the reference BZ. In such instances, the wind farm would not be fully hedged. Alternatives could include providing additional CI-FTRs on secondary paths (complex design) or exceeding the physical interconnector limit (revenue adequacy issues for the concerned TSO since CI may no longer cover the contract values). In such cases, joint ownership of the hybrid links across all TSOs involved in the project or other socialization mechanisms (as defined in the CI sharing methodologies for instance) can distribute the costs and help TSOs to remain revenue adequate.. Besides, the free allocation round of FTR would need to be aligned with the current auctioning process coordinated by the Joint Allocation Office (JAO). Today, FTRs are only auctioned with delivery periods up to a year. A long-term support scheme would therefore require either regular re-allocation rounds or regulatory changes to lengthen the time coverage of such contracts. The latter may impose additional financial pressure on TSOs beyond a certain horizon due to the rising uncertainty of the network state at delivery and the obligation to remunerate the volumes sold (firmness). Forward looking, **the volume risk we describe here should be addressed more closely** when planning the efficient grid sizing of hybrid projects.

*Option 2*: As opposed to CI-FTR based on a fixed volume, CI-CfD are usually designed 'as-produced', which means they do not cover against dispatch restrictions . In other words, if operational deratings force the offshore wind production below its operational maximum, only the resulting dispatched volume is covered. Also, similar to CI-FTRs, **the revenue adequacy of the TSO owning the interconnector to the reference bidding zone (counterparty to the contract) might not be ensured** if/at times when the wind production exceeds the flow on the cable, i.e. the CI collected. This is further reinforced by the fact that the CI-CfD would have to co-exist with the present FTR mechanism. The same CI would have to be used to remunerate two instruments, which is currently forbidden by the regulation, and difficult to manage regardless.

*Option 3*: The TAG is activated if the total export capability of the offshore bidding zone is smaller than the total net installed offshore renewable energy in that bidding zone. This rule is suitable for all network representations (NTC, Flow-Based, Flow-Based with Advanced Hybrid Coupling). Furthermore, there is no interference with existing LTTR mechanisms.

## Implementation of the options

*All options:* **Article 19 of the Electricity Regulation** 2019/943 sets out rules on the allowed use of congestion income. Any option that would entail redistribution of (part of) that income, would thus require amending this Article.

*Options 1 & 2:* CI-FTR and CI-CfD mostly necessitate amendments of the **Forward Capacity Allocation (FCA) Regulation**, which oversees the forward allocation process. First, the objectives defined in article 3 would have to be adapted for both the CI-FTR and the CI-CfD, as this regulation aims, among others, at “providing non-discriminatory access to long-term cross-zonal capacity”. Second, both the CI-FTR and the CI-CfD would require a change to article 28 defining the general principles of forward capacity allocation. Furthermore, the CI-CfD would require amendments to several articles related to product design (articles 31, 35, 43 and 44), as it is not considered today as a Long-Term Transmission Right. Beyond the FCA Regulation, the CI-CfD would necessitate an amendment to article 73 of the **Capacity Allocation and Congestion Management (CACM) Regulation** defining the requirements for the methodology for sharing congestion income. Finally, it must be emphasized that both the CI-FTR and the CI-CfD conflict with **article 9.2 of the Electricity Regulation** 2019/943 stating that “long-term transmission rights shall be allocated in a transparent, market based and non-discriminatory manner through a single allocation platform”.

*Option 3:* Conversely, the TAG relates to operational capacity calculation and thus entail stronger legal focus on the **Capacity Allocation and Congestion management (CACM) Regulation**. In addition, the TAG would also require new articles to define precisely the structure for the practical operation of a calculation and compensation mechanism, with new roles and responsibilities of stakeholders (NEMOs and NRAs in particular). Finally, the TAG would also require a change to **article 9.2 of the Electricity Regulation**.

**Summing up**, the TAG comes out as the preferred mechanism if any congestion income re-allocation is to be done: it is focused on the issue identified, it does not create overcompensations and related issues, it is realistic and scalable from an operational standpoint, and implementation is not expected to be more challenging than alternative options. It acts as a safeguard for the offshore producer when the transmission capacity allocated to the market is operationally decreased below a critical threshold. Also note that Advanced Hybrid Coupling should also partly address the issue in the Flow-Based regions if it is implemented (as currently planned), as it releases more capacity and should thus decrease the activation frequency of the TAG.

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## LIST OF ABBREVIATIONS

ACER	Agency for the Cooperation of Energy Regulators
ATC	Available Transfer Capacity
BZ	Bidding Zone
CACM Reg.	Capacity Allocation and Congestion Management
CfD	Contract for difference
CI	Congestion Income
DAM	Day Ahead Market
EB Reg.	Electricity Balancing
EC	European Commission
ENTSO-E	European Network of Transmission System Operators for Electricity
FB(MC)	Flow-Based (Market Coupling)
FCA Reg.	Forward Capacity Allocation - Guideline
FTR	Financial Transmission Right
IDM	Intra-Day Market
LTTR	Long-Term Transmission Right
MS	Member State
NRA	National Regulatory Authority
OBZ	Offshore bidding zone
OWF	Offshore Wind Farm
PTR	Physical Transmission Right
SDAC	Single Day-Ahead Coupling
SIDC	Single Intra-Day Coupling
TAG	Transmission Access Guarantee
TSO	Transmission System Operator



## INTRODUCTION

The transition towards a carbon neutral economy by 2050 will require a large-scale electrification of energy usages, coupled with the decarbonization of the power system expected as one of the main levers. To this end and following the European Green Deal, the Commission proposed the European Climate Law (European Parliament, 2021) to provide the necessary legal framework. The 2050 climate-neutrality objective will also impact the trajectory for achieving this goal. In particular, the Climate Law enshrines an intermediate reduction target of GHG emissions by at least 55% by 2030 compared to 1990 levels, and it defines a process to define the 2040 target. To implement the 2030 target, the Commission presented 12 legislative proposals in the framework of the Fit-for-55 Package (European Commission, 2021 (a)). The recent European Commission's REPowerEU Communication (European Commission, 2022) will accelerate this transition without any doubt.

Offshore renewable energy has a key role to play in achieving such targets. As a matter of fact, recent projects analysed the potential in the North Sea<sup>1</sup>, the Baltic Sea<sup>2</sup> and in the Mediterranean Sea<sup>3</sup> and concluded that the potential of each of these sea basins is significant. The European Commission has therefore high ambitions in terms of further offshore renewable energy development (wind, but also wave and tidal) and this led to the definition of an EU Strategy on Offshore Renewable Energy (European Commission, 2020). The Strategy recognizes not only the environmental and climate benefits of offshore renewable energy (greenhouse gas emissions reduction and biodiversity protection) but also the social (more affordable and stable energy supply, helping to keep energy prices in check) and the industrial ones (opportunities for the European industry, creation of jobs and security of supply) for all sea basins as well as landlocked Member States.

While its potential is very significant, challenges from a technical, environmental, regulatory and economic point of views have to be overcome to fully exploit it. Planning is essential to minimize issues and costs. The impact assessment of September 2020 concluded that *"an integrated approach to develop and deploy further renewable technologies like offshore wind energy and other is missing. Enhanced and expanded measures under RED II could deliver a larger uptake of renewable energy in the EU"* (European Commission, 2020). In particular, the Commission, in its proposal for a revision of the TEN-E Regulation (December 2020), emphasizes the need to define offshore renewable generation to be deployed in each sea basin by 2030, 2040 and 2050 and to define integrated offshore network development plans. Furthermore, hybrids offshore projects, connecting more than one electricity market, are also a means to efficiently integrate offshore renewable energy as planning is coordinated across national boundaries.

From an economic and regulatory perspective, it is generally agreed that dedicated offshore bidding zones are the most efficient and cost-effective way to integrate offshore renewable generation in the European electricity system (cf. (THEMA Consulting Group, 2020), (ENTSO-E, 2021), (Orsted, 2020)). Compared to the integration into an existing bidding zone, the offshore bidding zone ensures a more efficient pricing and dispatching of electricity, by better reflecting the real value of available transmission cross-zonal capacity. Also, the management of offshore bidding zones is better aligned with the existing regulatory framework. On the other hand, offshore bidding zones may reduce market

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<sup>1</sup> See PROMOTioN project, <https://www.promotion-offshore.net/>.

<sup>2</sup> Baltic InteGrid, <http://www.baltic-integrid.eu/>.

<sup>3</sup> Guidehouse & Sweco (2020), <https://guidehouseinsights.com/news-and-views/offshore-grid-potential-in-the-mediterranean>.

prices and revenues received by offshore generators when compared to a situation where the offshore installation would be integrated into an existing onshore bidding zone (also referred to as 'home market design'). This occurs since the offshore bidding zone more precisely reflects the value of energy and the transmission capacity for the offshore area where the wind farm is located, by integrating the constraints directly in the market clearing instead of solely relying on ex-post remedial actions. In practice, and when compared to an alternative integration in the onshore (domestic) market,, the offshore bidding zone design tends to represent a shift of the value of the hybrid project from the offshore generator to the owner of the transmission network (TSO) in the form of network congestion incomes. This might hamper the further development of offshore renewable energy in some cases: (THEMA Consulting Group, 2020) showed that the effect on revenues is highly dependent on grid topology and that for over half of the projects the median revenue effect under a Net Transfer Capacity (NTC) approach was around 1%, while up to 11% for few particular hubs where transmission capacity was tight.

**The objective of this report** is to assess market-based options to alleviate this potential risk for the business case of offshore renewable energy when OBZs are established, and to propose concrete policy options and recommendations on the way forward. To this end, the report is structured as follows: first, we describe the current mechanisms by which congestion income is calculated and allocated. As a complement, we provide in a second section an overview of the evolution of congestion income over recent years in the EU. Third, we analyse the case of hybrid offshore assets and why their unique situation calls for specific measures in order to create a level-playing field with other (onshore) assets. In section 4, we consider a range of dedicated options to mitigate the issue and evaluate them. Section 5 provides legal requirements for implementing these options before we then conclude and provide recommendations on the way forward.

## **1. CURRENT PROCEDURES FOR CALCULATING AND ALLOCATING CONGESTION INCOME**

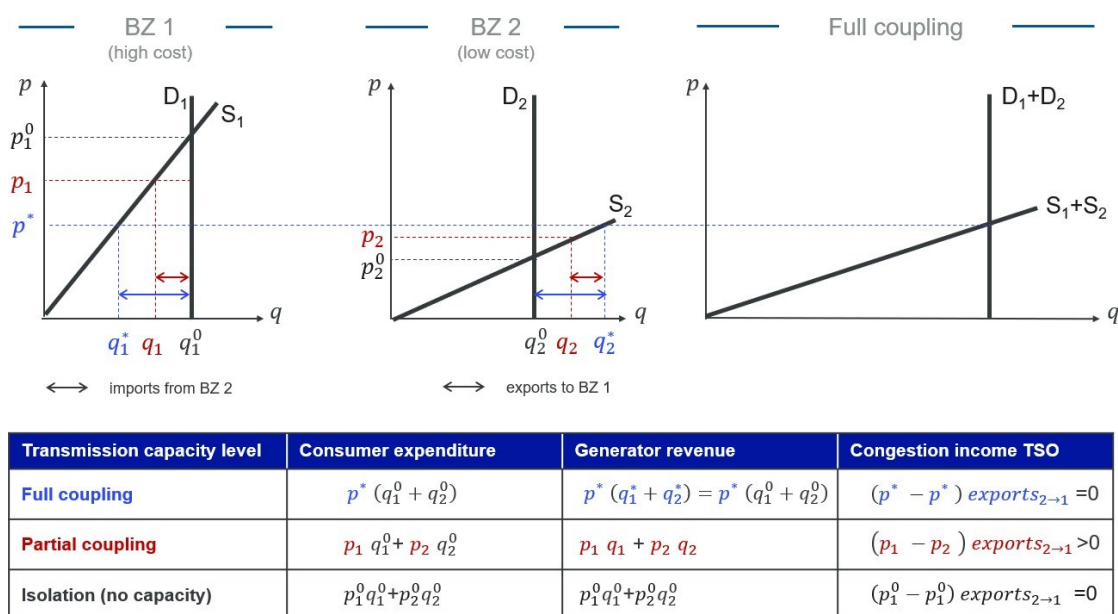
Before we discuss the risks involved in the operation of offshore assets in dedicated bidding zones and the options to support investment, we deem it relevant to provide first a definition and interpretation of the congestion income. We then present current methodologies to calculate and distribute it among transmission system operators.

### **1.1. Congestion income: definition, economic interpretation and calculation**

Congestion in a power system is a state that occurs when electricity network constraints become restrictive for some energy transactions. It is a natural consequence of having only a finite amount of transmission capacity. This is conceptually illustrated in Figure 1 for two bidding zones (BZ), one with a high generation cost (supply S1, BZ1), the other with a low generation cost (supply S2, BZ2). Demand D is assumed to be identical for the sake of simplicity.

When transmission capacity is abundant, the marginal cost of supplying electricity is identical across connected regions, implying full coupling and a single clearing price. Electricity has the same value everywhere and additional transmission capacity would not further reduce total generation costs. This is in fact the rationale behind the definition of a Bidding Zone: if the transmission between BZ1 and BZ2 were structurally (always) abundant, the latter are completely homogeneous and do not require explicit differentiation. If however transmission capacity becomes at times binding, congestion costs arise: the marginal cost of supplying electricity is no longer homogeneous but determined by regional generation costs. A significant lack of transmission capacity between areas should therefore signal the need to consider separate bidding zones. In this sense, a key factor to ensuring a level-playing field between assets is to ensure that a good

bidding zone design - where there is no structural congestion internally- is met not only in some locations but across the entire market.



Source : ENGIE Impact

**Figure 1: Congestion income**

With inter-zonal congestion, part of the cheap supply from the exporting BZ cannot be physically transmitted to the importing BZ. The missed-out cheap exporting generation must then be replaced by more expensive generation directly in the importing zone. In this case, prices, reflecting marginal costs, are said to “decouple”. They become typically greater in high-cost locations (importing bidding zones) compared to low-cost locations (exporting bidding zones). Consequently, buyers in the high-price zone must pay more for the energy they buy than what the generators in the low-price zone are paid for producing that same energy. This creates a financial surplus known as congestion income (CI), which reflects the value of the missing cross-zonal transmission capacity that would be required to fully couple all cross-zonal trades. It is accrued by the owner of the transmission network (typically also the system operator in Europe, commonly referred to as TSOs) when allocating transmission capacity implicitly (in case of market coupling, the preferred option in European wholesale markets) or explicitly (where energy and transmission are auctioned separately). In accordance with this, the Commission Regulation (EU) 2015/1222 (CACM Regulation) defines congestion income as the “revenues received as a result of [transmission] capacity allocation”.

Transmission capacity is thus remunerated at its marginal value, which corresponds to the regional price difference. Congestion costs (and incomes) do not indicate inefficiencies. On the contrary, the CI sets the right incentives to further develop or reinforce the grid where it is large. Full coupling across regions with no CI, on the other hand, can indicate overinvestment in transmission capacity. This is why one should expect CI to always be a normal outcome of a well-designed and functioning market since there is a social-welfare balance between additional grid expansion and market coupling benefits. The aim is thus never to build an over-dimensioned grid (paid by consumers) that would remove all congestions.

Historically, market participants would bid for energy and transmission separately (explicit auction for interconnector capacity). The congestion rent was then directly available in the form of capacity payments to transmission owners. In today’s day-ahead markets, transmission capacity is allocated implicitly in energy auctions via European market

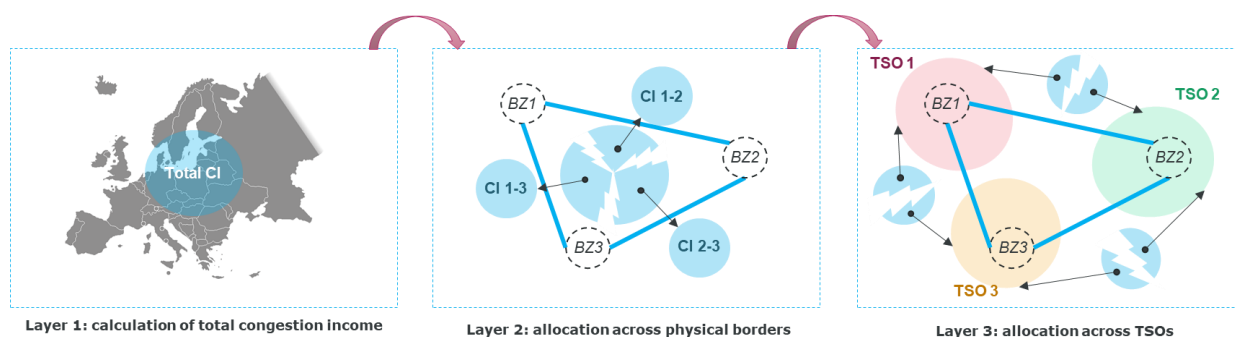


coupling. Cross-zonal transmission constraints are internalized and energy prices directly reflect the value of congestion between BZs. The congestion income is then paid implicitly, i.e. collected from the economic surplus that remains unallocated to market participants at the settlement phase (total consumer expenditures minus total generator revenues).

More generally, the congestion income represents the revenue collected by TSOs from the allocation of cross-zonal transmission capacity over relevant market timeframes. The rules for the capacity allocation, as well as for the allocation of CI across borders are defined and harmonized at Capacity Calculation Region (CCR) level<sup>4</sup>.

In forward markets, energy products (e.g. futures) do not embed any implicit representation of the transmission system since they are financial instruments, not binding for physical delivery. On the other hand, transmission products are explicitly sold by TSOs in the form of Long-Term Transmission Rights (LTTRs) on each interconnector. LTTRs can take the form of physical or financial transmission rights. Maximum allocations are based on estimates of the cross-zonal capacity available at delivery. These LTTRs entitle their owners to recover part of the congestion rent generated at the day-ahead stage (see below) and thereby to reduce their exposure to volatile regional price differences. The revenues from the forward LTTR sales represent a first source of congestion income that is directly allocated since the latter forward auctions are performed at border level (no need for a border allocation methodology). Besides revenues, these contracts also entail a financial obligation for TSOs to ensure the firmness of the capacity they sold, and to remunerate the owners who later exercise their contracts.

The day-ahead market (DAM) is a daily pan-European auction wherein cross-zonal transmission capacity is implicitly allocated within the market clearing algorithm Euphemia. The Congestion Income Distribution Methodology (CIDM) - see (ACER, 2018) – is the main reference document for this timeframe. It sets out the calculations in three separate “layers”, as illustrated by Figure 2.



Source : ENGIE Impact

**Figure 2: CIDM calculation layers**

The total congestion income collected at CCR level is first calculated through the Layer 1. Through Layer 2, this income is then distributed across relevant borders. Finally, Layer 3 covers the split among TSOs at border level. Layer 1 and 2 are detailed below, while Layer 3 is covered in Section 1.2.

<sup>4</sup> [https://www.entsoe.eu/network\\_codes/ccr-regions/](https://www.entsoe.eu/network_codes/ccr-regions/)

**Layer 1:** First, the total congestion income generated in the system follows the general description given above and can be calculated as:

$$Total\ Congestion\ Income = \sum_{buyers} cash\ out - \sum_{sellers} cash\ in$$

Since the DAM currently operates at hourly granularity, for each hour the total congestion income is the sum of all payments by buyers (consumers), minus the sum of all payments to generators. Payments are to be understood as the product of the contracted volume of energy (MWh) times the zonal price (€/MWh).

**Layer 2:** The total congestion income is then broken down into individual border contributions to determine which congested links are responsible for restricting energy exchanges. However, the methodology to do so is not unique because it strongly relies on the general representation of the network across each border. Currently, two main representations are in force across EU CCRs: the Available Transfer Capacity (ATC) and the Flow-Based (FB) methodologies. Today, all CCRs except Central Western Europe (CWE, covering FR, BE, NL, DE & AT) follow the ATC representation. Bidding zones connected via ATC links can exchange energy up to a nominal (explicit) value set by TSOs. The physical characteristics of the grid are largely simplified and commercial transactions can transit in full through the ATC link according to this representation. Thus, one of the natural outputs of the market clearing is the energy flow between ATC regions. The congestion income between two ATC zones A and B can therefore be directly computed ex-post as:

$$Congestion\ Income_{A-B} = Flow_{A-B} * \Delta P_{A-B}$$

If both prices  $P_A$  and  $P_B$  are coupled (equal), there is no congestion income on this border and the value of transmission capacity is zero. However, if a price spread  $\Delta P$  exists, the congestion income is equal to the latter taken in the positive direction times the flow between the zones (additional transmission would reduce total costs or increase social welfare by the regional price difference, reflecting marginal costs). The sum of the congestion income across all borders is then of course equal to the total congestion income as defined above.

On the other hand, the FB representation is only employed in CWE (soon also in the Core CCR<sup>5</sup>). This approach accounts for the fact that in reality electricity flows cannot be fully controlled in a meshed AC grid. So-called Critical Network Element & Contingency (CNECs) are defined across the system, which represents elements temporarily at risk of being congested. Energy transactions are then constrained by the Net Position (NP) of the bidding zones (net import or export balance, cf legal definition in CACM Reg. Article 2.5) which must collectively not overload any CNECs. As a result, the market clearing algorithm finds the optimal net position for each FB bidding zone, but does not deliver explicit bilateral flows like the ATC method. This means that the above formula for the congestion income between two zones is not directly applicable, because the flow variable is not known. Equivalent commercial flows must first be computed via an arbitrary methodology, since for the same set of NPs, there can be several ATC flow topology solutions.

The chosen approach is detailed extensively in (ACER, 2017) and (CWE TSOs, 2020). In brief, equivalent flows within CWE known as Aggregated Additional Flows (AAFs) are computed for each cross-zonal CNEC as follows:

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<sup>5</sup> See <https://www.jao.eu/core-fb-mc>

$$AAF_{CNEC} = \sum_{i=1}^{BZ} PTDF_{CNEC,i} * NP_i$$

where:

- BZ is the total number of Bidding Zones (excluding virtual hubs)
- $PTDF_{CNEC,i}$  is the Power Transfer Distribution Factor of the CNEC for Bidding Zone i
- $NP_i$  is the Net Position of Bidding Zone i

In a second stage, all AAFs related to cross-zonal CNECs across a specific border can be summed to obtain the total equivalent flow value between two CWE Bidding Zones.

Given this definition however, AAFs are not sufficient to fully balance all NPs in the FB domain. This is because they are only calculated on internal CWE borders and disregard flows exiting and re-entering the domain (external loop flows). A purely fictive “Slack Zone” is therefore used to compute external AAFs and balance the system. This results in two different congestion income ‘pots’:

$$Internal\ Pot = \sum_{b=1}^{internal\ borders} |AAF_b * \Delta P_b|$$

$$External\ Pot = \sum_{b=1}^{external\ borders} |AAF_b * \Delta P_b|$$

In theory, the sum of both pots should equal the total congestion income in the system. However, because the pots only consider positive border contributions due to the use of absolute values, the sum can at times be greater. In such cases, a proportional rescaling is applied to ensure the calculation of the total congestion income remains consistent.

The intraday market (IDM) follows suit on the DAM and allows participants to readjust their positions before final delivery. For the most part, the IDM operates on a continuous trading basis, by means of which participants are matched bilaterally as soon as they enter their bids into the system. Cross-zonal orders are matched on a first-come first-served basis, under the condition that there is sufficient intraday ATC left. Hence, at the intraday timeframe today, transmission capacity is largely allocated implicitly and for free to the fastest traders. This emphasizes the need to introduce coupled auctions for the intraday timeframe for efficient pricing and allocation of transmission capacity.<sup>6</sup> No congestion income is generated from continuous intraday trading. Only FR-DE, SI-HR and CH-IT requested an explicit allocation, and in which case the proceeds from the capacity sales represent an income immediately available for TSOs.

The EU ambition to homogenize single day-ahead coupling (SDAC) and single intraday coupling (SIDC) methodologies and reinforce market integration led to the launch of several local intraday auctions in some CCRs (SWE, CWE, IU). These auctions are executed in parallel with continuous trading and allocate cross-zonal capacity implicitly. Yet, the wider integration of cross-zonal pricing in intraday auctions is an important milestone for which developments are still underway.<sup>7</sup> As of today, CWE auctions still remain decoupled: even if cross-zonal products are accepted, the clearing only generates a price for the bidding zone(s) considered. Foreign bids are paid at the local clearing price if the network allows it and there is thus no congestion income arising from such designs. Only few intraday auctions may already result in price decoupling and congestion income generation

<sup>6</sup> (Tractebel Impact & SWECO, 2019)

<sup>7</sup> [https://www.entsoe.eu/network\\_codes/cacm/implementation/sidc/#future-development](https://www.entsoe.eu/network_codes/cacm/implementation/sidc/#future-development)

(SWE between ES and PT, IU between GB and SEM). In general, however, the target calculation methodologies for the intraday market are aligned with that of the day-ahead market. When the pan-EU intraday coupling solution is fully implemented, the IDM will therefore produce congestion income in a similar fashion.

The balancing markets allows TSOs to contract services with flexible assets in order to secure the energy delivery. Indeed, if congestion unforeseen by the market schedule arises in the physical network or if supply and demand are not fully matched in real time, remedial actions (countertrading, redispatching & other congestion management measures) must be taken. For long, the balancing market has consisted of bilaterally-agreed reservation/activation payments made by TSOs to Balancing Service Providers (BSPs) within their perimeter. As such, the generation of balancing congestion income until now has remained marginal. However, two of the four European balancing platforms for the exchange of balancing energy or for the imbalance netting process (IN-Platform, RR-Platform) have already gone live, with other two shortly expected (aFRR-Platform, mFRR-Platform). Moreover, cross-zonal initiatives for the coordinated procurement of balancing capacity are now coming to fruition in several CCRs (Core, Baltic)<sup>8</sup> or being designed (Nordics)<sup>9</sup> for the exchange of balancing capacity. These will result in multiple security-constrained auctions based on marginal pricing, which implies that in case of congestion, balancing prices will decouple and a balancing congestion income will be generated. Through the balancing auctions, individual TSOs will emerge as either net balancing energy provider or buyer. Nevertheless, the resulting balancing CI is still eventually redistributed among the TSO body (to those acting as net providers, see (ACER, 2020)).

## **1.2. CI distribution among TSOs and usage**

### *1.2.1. Legal background*

The need for the establishment of congestion income distribution methodology among TSOs is first set out by Article 73 of the Capacity Allocation and Congestion Management Regulation (European Commission, 2015). but also by Article 57 of the Forward Capacity Allocation Regulation (European Commission, 2016) and Article 40 of the Electricity Balancing Regulation (European Commission, 2017). The resulting methodologies are defined in the Annex I of the ACER decision No 07/2017 of 14 December 2017 on the congestion income distribution methodology and in the "All TSOs' Proposal for a Congestion Income Distribution (CID) methodology in accordance with Article 57 of the FCA of the 15<sup>th</sup> of March 2019 (approved by all Regulatory Authorities of the European Union on the 22<sup>nd</sup> of May 2019). However, methodologies at European level stay general and they are completed by a set of implementation details for each CCR.

Regarding the usage of the congestion income, Article 19 of the Electricity Regulation 2019/943 strongly regulates its allocation. Besides, Article 63 defines possibilities for exemptions that can apply to new interconnectors and hence possibly hybrid ones, as referenced in recital (66). We develop this further in section 1.3

### *1.2.2. ACER congestion income distribution methodology*

As mentioned in the Annex I of the ACER decision No 07/2017 of 14 December 2017, the CID methodology should cover both the day-ahead and intraday timeframes. However,

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<sup>8</sup> <https://www.acer.europa.eu/events-and-engagement/news/acer-decides-electricity-cross-border-capacity-allocation-methodologies>

<sup>9</sup> <https://extranet.acer.europa.eu/Media/News/Pages/ACER-publishes-four-decisions-creating-a-Nordic-electricity-balancing-capacity-market-.aspx>

since the intraday capacity pricing methodology is not defined yet, the CID methodology only covers the day-ahead timeframe.

As presented in Section 1.1, the congestion income distribution is designed in three layers:

- 1) For each CCR, the congestion income generated by exchanges within a CCR is defined and collected;
- 2) The congestion income of a CCR is distributed among the bidding zone borders of a CCR;
- 3) The congestion income attributed to the bidding zone border is distributed among TSOs.

The congestion income attributed to a bidding zone border shall be calculated as the absolute value of the product of the commercial flow (AAF for CCRs applying the FB approach and allocated capacities on the bidding zone border for CCR applying coordinated NTC) multiplied by the market spread.

In addition, it has to be noted that in case the sum of congestion income attributed to all bidding zone borders within a CCR is not equal to the total congestion income generated by electricity exchanges within a CCR, the congestion income attributed to the bidding zone borders within a CCR (and external borders where relevant) shall be adjusted proportionally in order to match the total congestion income generated by electricity exchanges within a CCR.

### **Distribution of the border allocation across relevant TSOs (layer 3)**

The distribution of the congestion income between the TSOs is based on sharing keys. In general, for the bidding zone borders where congestion income was calculated based on allocated capacities or AAF (as detailed in Section 1.1), the TSOs on each side of the bidding zone border shall receive their share of net border income based on a 50%-50% sharing key. However, specific sharing keys can be used in the case of different ownership shares or different investment costs.

The congestion income calculated based on external flows shall be attributed to the TSO(s) of a bidding zone for which the associated external flow was calculated and have interconnectors through which the external flows are realized. In case the bidding zone border consists of several interconnectors with different sharing keys, or which are owned by different TSOs, the net border income shall be assigned first to the respective interconnectors on that bidding zone border based on each interconnector's contribution to the allocated capacity.

It has to be noted that in case specific interconnectors are owned by entities other than TSOs, the reference to TSOs in the methodology presented above shall be understood as referring to those entities.

#### *1.2.3. Regulated usage of congestion income by TSOs*

TSOs being regulated entities, the requirements for the usage of the congestion income they collect are set out in Article 19 of EU Regulation 2019/943. We detail below the main implications.

First of all, even if congestion income is a natural consequence of the market design, TSOs should aim at maximizing the cross-zonal capacity across market timeframes to foster liquidity and zonal integration. In other words, they should not try to artificially curtail transmission capacity in order to maximize their revenues through congestion income. Moreover, the priority objectives for the allocation of these revenues are:

- To guarantee the availability of the allocated capacity (cost of remedial actions and other congestion management measures). This also includes the cost of firmness, e.g. the compensation for LTTR holders whose contracts (either Physical or Financial Transmission Rights) cannot be exercised due to reduced network availability at delivery.
- To remunerate market participants holding LTTRs and entitled to compensation (FTRs or non-nominated PTRs).
- To maintain existing network infrastructure, improve system operations and invest in new transmission assets in order to increase the amount of cross-zonal capacity in the long-term.
- To be transparent on the usage of such revenues and publish a yearly monitoring report (amount collected, allocation...)

The base rule for the remuneration cost of LTTRs is to use a 50%-50% sharing key across TSOs on both sides of a border (aligned with the income sharing key). Currently, the DAM is designed so that the total remuneration cost is always lower or equal to the total congestion income<sup>10</sup>. This ensures that the system as a whole is not loss-making for TSOs. However, it may happen for some borders that the remuneration cost exceeds the congestion income. In order to prevent the related TSOs to incur a deficit, the extra cost can be shared pro-rata with the other borders: this is known as the "socialization process". In this context, we will see later in this report (Section 4.4.1) that some of the options assessed to alleviate the financial risks of offshore generators raise serious issues.

As explicated in Art.47.2 of EU Regulation 2019/944, each TSO must "ensure it has the resources it needs in order to carry out the activity of transmission", i.e. that the above financial obligations can be covered in full by its revenues (revenue adequacy). It is only when these objectives have been met that the *"revenues may be used as income to be taken into account by the regulatory authorities when approving the methodology for calculating network tariffs or fixing network tariffs, or both"* (Article 19.3 of EU Regulation 2019/943).

A summary of TSOs' congestion-related cash flow across market timeframes is given in Table 1.

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<sup>10</sup> See Long-Term Allocation (LTA) inclusion patch: section 4.3.1 of (NEMO Committee, 2020)

	Forward	Day Ahead	Intraday	Balancing
Revenues	Long-term CI (LTTR sales)	DAM CI	None (continuous & local auctions) IDM CI (coupled energy auctions & explicit capacity auctions)	Balancing CI (coupled balancing options) TSO exchanges Imbalance settlement
Expenses	Auction organization	Firmness LTTR remuneration RA	Firmness RA	Balancing (TSO exchanges, BSP settlement, others) Imbalance settlement

RA: (costly) Remedial Actions. Understood here as including various preventive & curative congestion management practices such as countertrading, redispatching, capacity curtailment.

**Table 1 Congestion income and related expenses per market timeframe**

### 1.3. Exemptions and merchant investment in transmission capacity

Regulatory exemptions can be requested for new projects by transmission owners as per Article 63 from EU Regulation 2019/943. These exemptions are only granted temporarily (typically up to five years) and must result from exceptionally high financial costs and risks which would otherwise compromise the asset development. Additional conditions must be met: the investment must enhance competition in electricity supply whether or not the exemption is granted, and no cost must have been already recovered from charges on the interconnector.

Exempt projects can in principle be relieved from several responsibilities:

- From the need to prioritize the CI usage on the objectives described above
- From having to freeze the residual CI revenue in an account as a basis for network tariffs calculations
- From having to grant full third-party access to the interconnector, for a limited time and under strict conditions
- From some ownership unbundling obligations
- From respecting certain legal notice periods with respect to establishing tariffs, access, capacity allocation and congestion management procedures.

An application must be submitted to the local regulatory authorities which will take a case-by-case decision (possibly with support from ACER) based on the robustness of the justification, the duration of the exemptions and its impact on competition & on the functioning of the internal energy market. According to Art. 63, applications can be submitted for 1) new High Voltage Direct Current (HVDC) cables, 2) new AC cables in exceptional cases where the costs and risks are particularly high and 3) "significant increases of capacity in existing interconnectors", although no minimum value is provided. However, even under exemptions, congestion management rules must still be established and the capacity offered to the market should still be maximized.

The case when the transmission owner is not a regulated TSO but a private legal entity ("merchant" investment) is treated quite clearly by the regulation. As per Article 1 of the CIDM: *"The TSOs operating these assets shall conclude the necessary agreements*

*compliant with this CID methodology with the relevant transmission asset owners to remunerate them for the transmission assets they operate on their behalf”.*

Art. 5 further specifies that TSOs and private owners are not differentiated when it comes to defining sharing keys. The congestion income accrued by the system operator must therefore be fully redistributed to private transmission owners in their control area. The latter must in turn fulfil their financial obligations in terms of maximizing the available capacity and remunerating LTTR as well.

#### **1.4. Main take-aways on congestion income**

- Congestion income remunerates TSOs for the value the transmission system brings to the system when not all energy transactions can be executed. Specifically, in a zonal market, the CI remunerates only the allocated cross-zonal capacity.
- It is collected across all market timeframes (forward, day-ahead, intraday, balancing) via methodologies that depend on the network representation at that stage and in the specific CCR considered: explicit vs implicit, FB vs NTC. The mechanisms are built to never yield negative payouts and ensure the revenue adequacy of TSOs.
- Its usage is regulated by the current legal framework. Congestion income must primarily be used as a signal to support grid availability (including firmness), investments (to self-regulate) and to fulfill TSOs’ other financial obligations.

The level of congestion income collected is intimately linked to:

- How coordinated generation and investment planning are. In theory, the market is already designed so that capacity shortages may create simultaneously scarcity rents for producers and congestion rents for network operators. TSO-TSO cooperation mechanisms, capacity remuneration mechanisms and other long-term development plans such the TEN-E Regulation provisions and ENTSO-E’s TYNDP also contribute to improve this aspect.
- How well the BZ topology reflects grid constraints. This is a complex and dynamic issue, which is reviewed periodically via the Bidding Zone Review.
- How much of the network is embedded into the market clearing. The legal framework has evolved over recent years in order to maximise the amount of cross-zonal capacity made available to the markets (i.e. the minimum 70% threshold for capacity made available to the market). Indeed, there would otherwise exist a natural incentive for TSOs to restrict transfer capacity for system security reasons, which transfers internal congestion to the zonal borders and generates an income. Meanwhile, physical congestion that does not generate CI (e.g. intra-zonal congestion) is mostly a cost for TSOs, in the form of necessary remedial actions.

## **2. HISTORICAL EVOLUTION OF CONGESTION INCOME IN EUROPEAN POWER MARKETS**

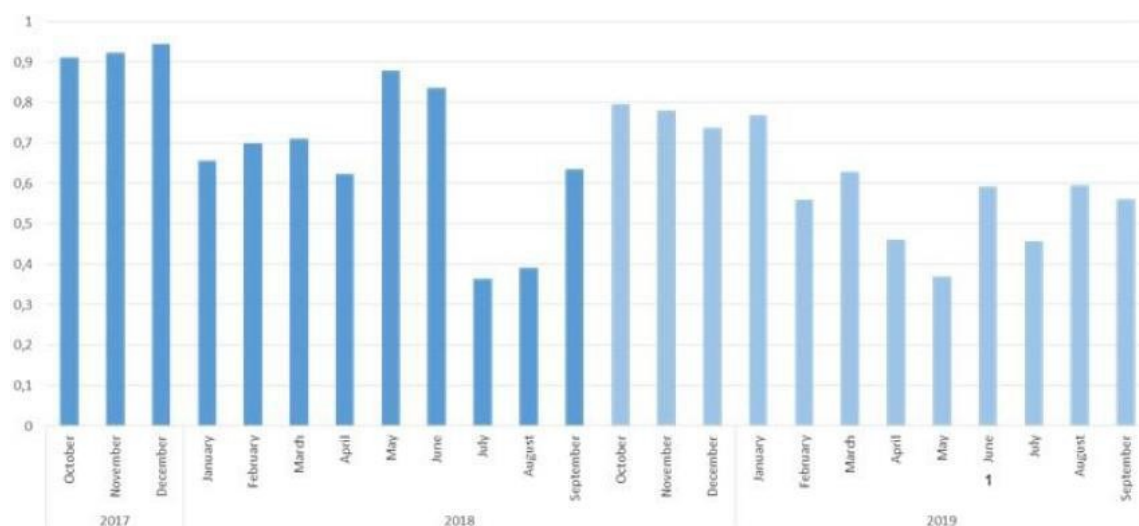
This section provides some highlights on the congestion income collected on the day-ahead market in the different CCRs, and its distribution across borders.

For CWE, an extensive analysis was performed by TSOs twelve months after the split of the German-Austrian bidding zone in order to assess the redistribution impacts of this market change, which occurred on the 1<sup>st</sup> October 2018. We provide insight on some of the main findings from (CWE TSOs , 2020) below.



First of all, it is relevant to stress that congestion occurred frequently in CWE despite the fact that for similar physical interconnectors, the Flow-Based methodology can allocate more capacity to the market than ATC. Hours with at least two decoupled prices in the region accounted for 35 to 90% of all monthly hours on average. See Source :

Figure 3.



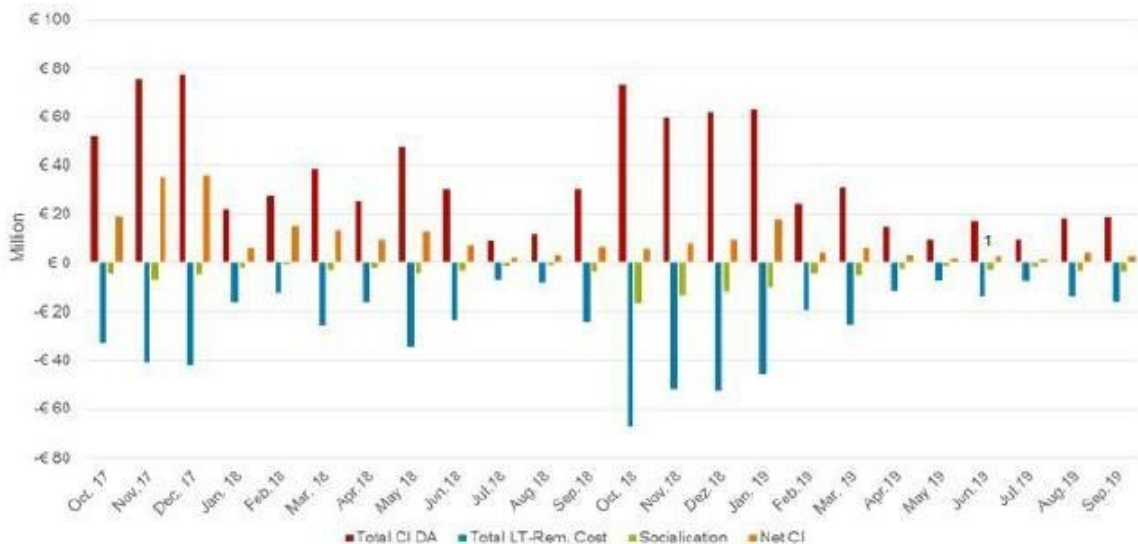
Source : (CWE TSOs , 2020)

**Figure 3: Ratio of congested hours by total hours in CWE**

Source :

Figure 3 demonstrates some seasonality in the congestion profiles, with typically more decoupled hours observed over winter. This is mostly attributed to system demand peaking in cold months with the significant influence of heating<sup>11</sup>. However, congested hours as defined in this analysis, do not provide information on the scale of the decoupling, i.e. how wide the associated price spreads were, or in other words the amount of congestion income generated. Next, the resulting congestion income generated over the period is given by Figure 4.

<sup>11</sup> For instance, 1.7 GWe additional capacity per degree temperature drop was historically required in France according to (Dittmat, 2008) due to increased needs for electric heating and lighting.



Source : (CWE TSOs , 2020)

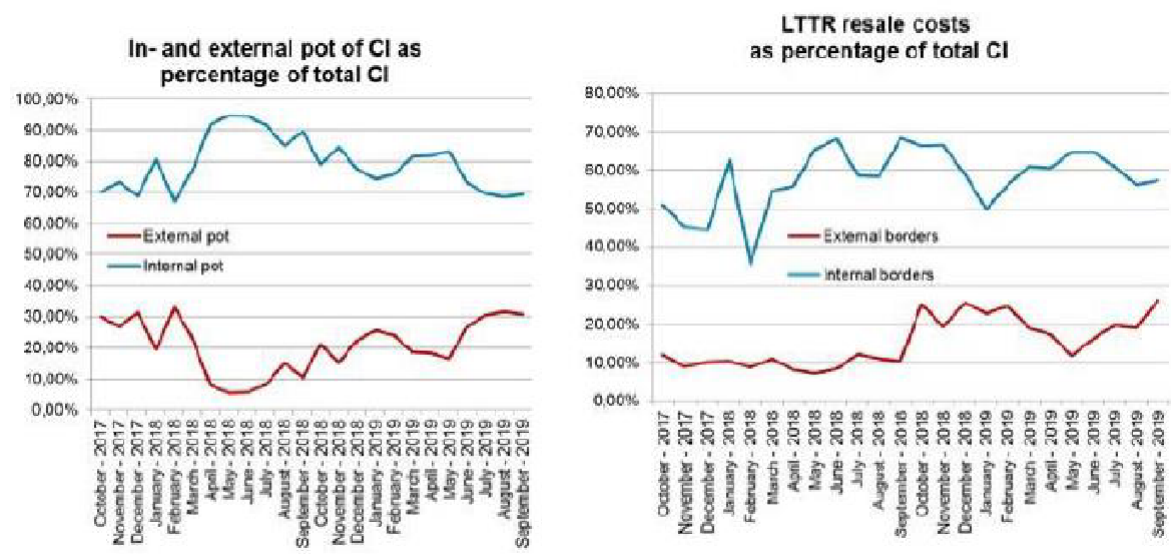
**Figure 4: DAM congestion income timeline and distribution**

The Total CI (red) represents the gross income generated over CWE according to the general formula laid out in the CIDM layer 1. Since CI is a function of volumes exchanged and price spreads, the observed seasonal variations are a direct consequence of these variables. In winter, demand and congestion rates are typically higher (more network constraints). This also impacts price spreads which tend to increase in periods of high demand as the merit orders become steeper. From this total revenue (red), the total LT remuneration cost (blue) - which corresponds to the sum of payments to entitled LTTR holders - is then discounted. The resulting Net CI (orange) is always positive, which means that TSOs do not generate losses and remain revenue adequate over the DAM perimeter. This is secured by the DAM design itself, since the coupling process includes an enlargement of the Flow-Based domain to encompass all flows related to LTTRs. This step, known as the Long Term Arrangement (LTA) inclusion, ensures that enough capacity is “squeezed” out of the physical network to accommodate and remunerate all forward transmission contracts.

At times, the Net CI (orange) becomes very limited, which indicates that most of the transmission capacity available for the DAM was already contracted in the form of LTTRs. For instance, in October 2018 following the split between Germany and Austria, substantial price decoupling was observed between the two bidding zones, which resulted in an increase of congestion income. However, as LTTR auctions were launched in parallel for a transmission capacity of 4.9GW FTRs, the resulting net income remained stable. In other words, market participants were highly hedged and TSOs had to redistribute most of the income they collected. However, note that in such instances TSOs still earn congestion revenues across other timeframes (namely from the forward LTTR sales)<sup>12</sup>. This is further discussed in the next section. Although the total net income is always positive, this does not have to be the case for all borders. Some may produce a net deficit (when remuneration costs become higher than the collected congestion income on that border), which is then compensated by more profitable borders in the final balance. In such cases, the deficit on loss-making borders is shared across all profitable TSOs via the so-called “socialization” process (green). This ensures the revenue adequacy for all borders (incentive to remain in the system) and is an indicator for the amount of income redistribution among TSOs. The

<sup>12</sup> The share of congestion income as part of the total revenue portfolio can in fact vary substantially across TSOs and power systems. In 2020 for instance, RTE registered 11% of its profits from interconnector income, against 90% for Terna.

share of congestion income used for socialization typically varied between 3 and 24% over the studied period. Lastly, a view on the breakdown in internal and external pots is provided in Figure 5.

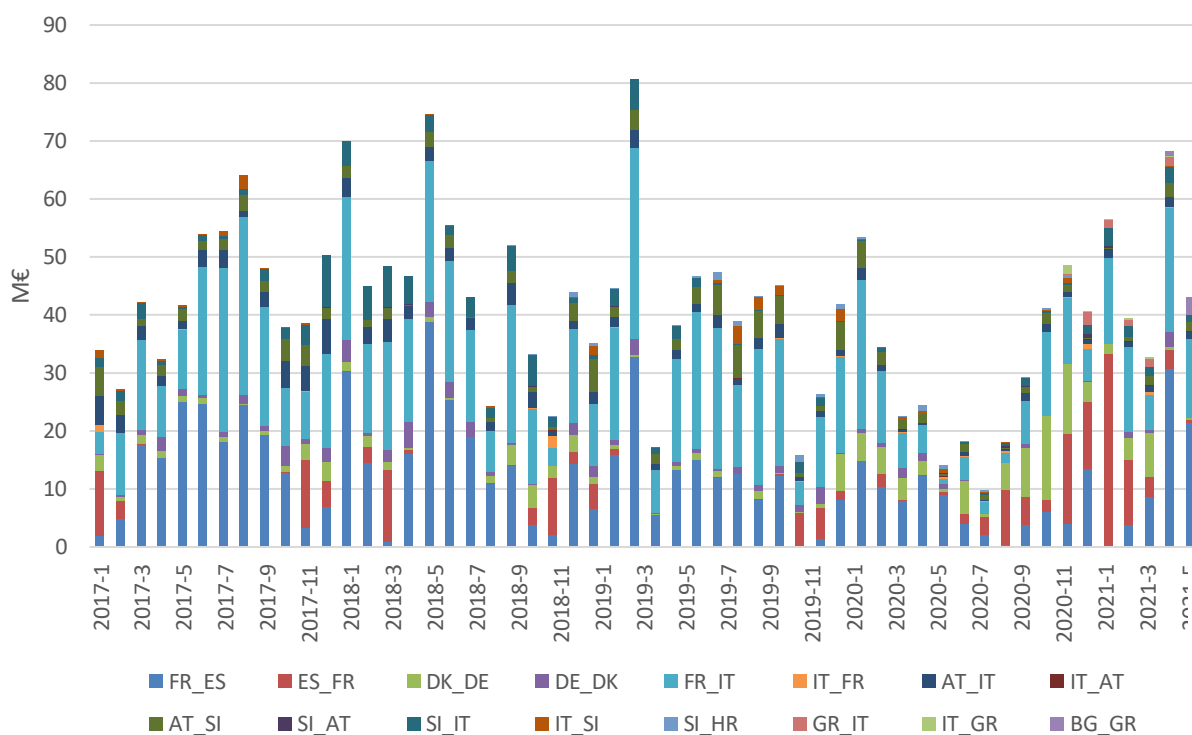


**Figure 5: Total CI breakdown (left) and Remuneration costs breakdown (right)**

The left chart displays the share of each pot in the total gross income. In this regard, the external pot which accounts for flows on external borders and back to CWE ranges from 5 to 30%. This is significant and shows the extent to which the Flow-Based representation is able to capture external loop flows which as a by-product of internal transfers. Since the external pot captures the CI between FB zones and the virtual "Slack Zone", the income gets eventually redistributed among physical CWE borders.

The chart on the right-hand side shows instead the remuneration costs across border types as a percentage of the total gross income. As an example, in September 2019, 58% of the total CI was used to remunerate internal borders and 27% to external borders, thus leaving a 15% net income margin to TSOs. Combining both graphs then allows to assess the profitability of internal & external borders. For every period, if the CI curve is higher than the sale cost curve, the pot considered yields a positive net surplus. For September 2019, the internal pot represents 70% of the gross income, with only 58% used for internal remuneration, thus generating a 12% net surplus. Meanwhile, the external borders only generate the remaining 3% net surplus for that period. Generally speaking, the sale costs for each pots seem to increasingly converge towards their respective CI, which seems to indicate either more participation in forward auctions, or lower premiums required by market participants (prices of LTTRs converge to their expected value at delivery).

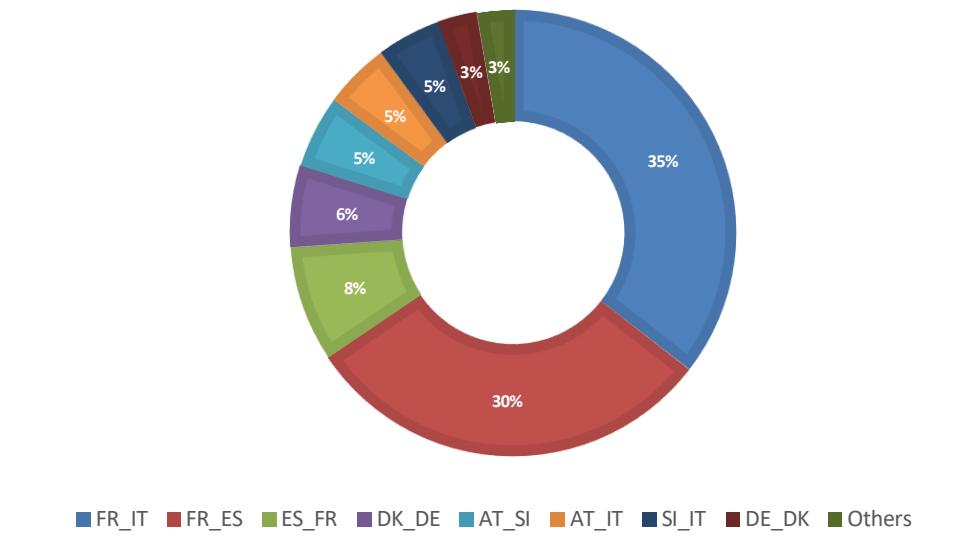
As this analysis was solely performed on CWE, we also provide a view on congestion income allocation for some CCRs under the ATC representation. Hourly data for continental borders was extracted from the Joint Allocation Office and aggregated at monthly granularity in Figure 6.



Source : ENGIE Impact

**Figure 6: Gross CI per ATC border on the DAM**

The data covers the period spanning from the 1<sup>st</sup> January 2017 to the 1<sup>st</sup> July 2021. The profile generally follows that of CWE for the overlapping period. On the more recent portion, one can notice the influence of the Covid pandemic over 2020, where particularly low congestion (demand) was registered. The gross income is typically concentrated in a few borders/directions which therefore designate consistent system bottlenecks. In practice, as per Figure 7: ATC gross CI distribution per border & directions, FR>IT, FR<>ES and DK<>DE account for more than 80%. On the other hand, some borders/directions generate very little income, either because they have sufficient capacity, or because the supply/demand in the neighboring BZs is such that the direction is rarely used (steady exports on A>B implies no flows or CI on B>A).



Source : ENGIE Impact

**Figure 7: ATC gross CI distribution per border & directions on the DAM**

### **3. THE CASE FOR HYBRID OFFSHORE PROJECTS**

Offshore wind is regarded as one of the most promising resources to achieve the ambitious renewable energy targets set out by the EU. In particular, hybrid offshore projects - which connect more than one BZ – can bring substantial socio-economic welfare improvements by allowing an increase in market integration, a more coordinated investment planning and a decrease in system costs. Besides, it also brings other benefits such as a lower need for additional connection points and a more limited impact on the environment than radial connections.

However, hybrid systems with dedicated offshore BZs (OBZs) are a new way to integrate large amounts of offshore wind and may lead to financial asymmetries compared to projects built as part of an existing BZ. Indeed, while the benefits are mostly system-wide, the economic risk can concentrate further on generators and wind developers due to specific market dynamics at play. This could become a deterrent for investors, who must assess the viability of the project, especially given the lack of experience in managing such novel models. Ultimately, the non-implementation of hybrid projects would adversely affect the wider system (and its consumers) for missing out on substantial benefits. In this section, we explore in more details the case for hybrid offshore projects.

#### **3.1. Offshore bidding zones and economic efficiency**

From an economic and regulatory perspective, it is generally agreed that dedicated OBZs are the most efficient way to integrate offshore renewable generation in the European electricity system (cf. (THEMA Consulting Group, 2020), (ENTSO-E, 2021), (Orsted, 2020)). Compared to the integration into an existing BZ, the OBZ ensures an efficient pricing of electricity by properly reflecting the value of available cross-zonal capacity. In principle, it provides therefore better price signals for production (dispatch), consumption (e.g. storage or hydrogen production) and investment decisions (generation, storage, electrolyzers, electricity and gas networks). It is also more flexible for renewable producers, as it unlocks access to more than one market.

On the other hand, the internalization of the hybrid interconnectors' capacity in the market clearing constraints leads to a different set of dispatch and prices, as it may restrict the ability of some market players to transact energy. If transmission is scarce, this information is given to the market and TSOs get remunerated accordingly via the higher congestion

rents they collect. As discussed in section 1.1, doing so now implies that producers in export-constrained areas (e.g. OBZ) become exposed to lower prices than consumers in import-constrained areas. The economic surplus is therefore distributed differently with a higher share incurred by transmission, which better reflects its scarcity. Note that in the long-term, the issue of structural transmission restrictions is addressed in particular by the implementation of the Trans-European Networks – Energy (TEN-E) Regulation (European Commission, 2022).

We argue that, in itself, this alternative welfare distribution does not provide any basis for the implementation of a reallocation methodology in favor of offshore renewable generators. On the contrary, it actually assigns more efficiently the margins to TSOs and producers for their system contribution. Put differently, in many of today's onshore BZs, the opposite dynamic takes place: congestion income tends to shift from TSOs to generators. In this sense, it is rather the status quo that favors onshore over offshore projects. This is also in line with the position that OBZ are the best way forward to integrate hybrid projects. Only investments already made in an existing BZ could legitimately advocate for a "make-good" compensation to ease the transition to dedicated OBZs.

This conclusion should hold true for any generally well-defined bidding zone. Nevertheless, hybrid offshore systems also present an unusual set of characteristics which, when integrated under an OBZ, may result in more strenuous risk exposure for offshore generators. We discuss these aspects in the next section.

### 3.2. Hybrid projects and transmission risk

Dedicated OBZs necessarily imply that offshore renewable generators are subject to additional transmission risk, compared to their integration into an existing (onshore) BZ. In dedicated OBZs specifically, this transmission risk is even exacerbated by the nature of the system itself - see Table 2.

OBZ integration		Onshore BZ integration
<b>Local supply</b>	Shallow supply curve composed of a single technology with 0 marginal cost & weather-dependent (intermittent) production.	Supply curve composed of multiple technologies, typically including dispatchable generation
<b>Load</b>	No local load <sup>13</sup> , demand is step-wise and fully driven by adjacent bidding zone prices (exports).	Local demand can already meet some of the production irrespective of import/export capabilities
<b>Transmission</b>	Cross-zonal hybrid cables: all explicit limits integrated in the market clearing	Intrazonal hybrid cables: do not restrict energy exchanges
<b>Balancing</b>	Offshore renewable generation registered as BRP, dedicated imbalance price. If no up-regulation on site, it must rely on onshore flexibility.	Offshore renewable generation part of a larger BRP portfolio with bidirectional flexibility, possibly also DSM and batteries.

**Table 2: Integration of hybrid assets: impact of design**

<sup>13</sup> One can expect that in the long term and depending on the technical options available, volatile offshore BZ prices could attract investment in batteries and electrolyzers, which would then create local loads.

Nowadays, new offshore renewable generation is integrated as part of an existing BZ of which the price reflects the balance between a rather diverse basket of generating technologies, the load and the exchanges. Physical capacity reductions or congestion that could occur on the hybrid links would not impact the dispatch of the offshore generation on the market. Instead, the TSO manages the congestion at delivery, usually via costly remedial actions, possibly requesting the offshore generator to reduce output (redispatch downward). When redispatched, the asset is then compensated at the market price in order to be made financially neutral and avoid gaming strategies. This means that the offshore generator has a natural hedge against the hybrid transmission risk in this solution.

Meanwhile, under an OBZ integration, the offshore generator has its own separate price point that only reflects the ability to export the wind production and transfer additional flows based on the hybrid transmission limits:

- If the full offshore production cannot be exported, i.e. if the dispatched production saturates all export directions and still remains below its operational maximum due to lack of transmission capacity: the zonal price is the marginal cost of the most expensive producing technology (the OWF) and effectively drops towards 0. More details on such situations are provided in Appendix C.
- If transmission limits allow the export of the full wind production and also transfer some additional onshore power, then the OBZ price typically converges to that of the neighboring BZs with which it has no congested link (usually the exporting ones).

In addition, balancing prices may also be impacted by the lack of upward flexibility in case of a mismatch between market schedule and real-time delivery, or in case of a security of supply issue. In a fully efficient and coupled balancing market, this is normally not an issue, as balancing services can be procured onshore to increase exports from the low-price zone to compensate for the reduced wind production. However, while the EU is making great strides in direction with the implementation of the Electricity Balancing Regulation (Commission Regulation (EU) 2017/2195), which aims to harmonize balancing markets with common balancing energy procurement platforms such as PICASSO, MARI or TERRE, the complete range of services and solutions may not yet be fully available in the very near term. Given the recent and shortly expected go-lives of the four European balancing platforms, the availability of such services and solutions may mostly depend on the joining date of concerned TSOs and the capability of the balancing platforms to incorporate new HVDC lines and OBZs in the respective algorithms. This should probably not be a substantial barrier considering the timeline of known future hybrid offshore infrastructure assets.

Meanwhile, under current regulation, the imbalance price must be calculated at imbalance price area level, which frequently corresponds to the BZ level, and the offshore generator will most likely have to register as Balancing Responsible Party (BRP) within the OBZ. As a result, if situations occur when the offshore generator cannot balance its position after the IDM gate closure, it may be exposed to additional costs in the form of inevitable imbalance payments. Furthermore, as discriminatory renewable priority dispatch is being phased out for large new renewables projects following EU Regulation 943/2019, close cooperation with neighboring TSOs will be necessary to cost-effectively support the balancing of the hybrid system.

It is therefore clear that the OBZ integration and the exposure to transmission constraints results in additional price and volume risk for the offshore generator, compared to renewable generation located in existing onshore BZs. The magnitude and direction of these effects can fluctuate according to market conditions and to the methodology used to represent the network constraints. It should however be noted that there are also benefits to the business case for hybrid projects that stem from having access to more than one market. As this report is more focused on risk, we do not cover these aspects extensively, but such benefits include lower exposure to negative prices, increased resilience thanks to access to multiple markets, or higher load factors in the long-term when the price signals attracts power-to-X technologies.



### 3.3. Impact of the network representation

If the transmission capacity available for cross-border trade is defined by the **Available Transfer Capacity (ATC)** methodology, the impact is generally negative when compared to an integration in an existing onshore BZ. For instance, the Thema study estimates this drop in their modelling exercise<sup>14</sup>, to average between 1 to 5% over the horizon to 2050, and up to 11% for some OWFs when there was significant congestion on the grid.. The authors also recognize that even higher figures may be expected in practice when considering alternative network topologies: *"the small scale of the assessed redistribution effect is clearly a consequence of the modelled topology [...]". Critically, the risk of network congestions occurring between an offshore hub and its home market is quite limited given the assumed topology and this limits any redistribution effect*". To this effect, we also provide a second quantification in Box 1 where the topology is purposely made structurally tight, and where transmission may further be reduced operationally. Under this stress test and for the year studied, we observe results in line with Thema's, which provides additional robustness to the quantified magnitude of the effect.

Alternatively, if the representation of the network constraints is **Flow-Based (FB)**, the impact is more delicate to assess because the OBZ exchanges can be impacted – negatively but sometimes also positively<sup>15</sup> – by transmission elements across the entire system. The hybrid links, if restricting, may be added to the list of so-called "Critical Network Element" (CNE) that form together the binding domain for energy exchanges within all zones under this representation (via the Power Transfer Distribution Factor – PTDF- matrix). This domain is in general larger than under the ATC approach, which means that the FB methodology typically provides more capacity to the market and may provide some relief in this regard to the OWF's volume risk.

Besides this general observation, there remains some regulatory uncertainty about the integration of OBZs in FB. This uncertainty relates to the treatment of High-Voltage Direct Current (HVDC) links – which should make up for the most part of hybrid offshore links – in this representation. Currently, flows on HVDC links are either forecasted and fixed accordingly by TSOs before the market clearing, or restricted by a dedicated CNE. To account for the impact of DC flows on other AC elements, the corresponding CNE capacities are usually derated (the expected HVDC flow is deducted from the final allocation as a means to reserve the capacity). In this sense, HVDC links benefit from priority access to the market. This is however not efficient because the reserved CNE capacity can become unused if the actual HVDC flows deviate from the expectations. Thus, a new proposal for equal access has been put forward by TSOs: the **Advanced Hybrid Coupling solution** (AHC – where 'hybrid' must not be mistaken with hybrid offshore systems but rather refers to general coupling of both AC and DC elements). With AHC, the full HVDC capacity is offered to the market and no CNE derating is performed. This is made possible thanks to the use of new virtual hubs in the PTDF to quantify the impact on other AC elements within the market clearing algorithm directly. The AHC proposal has, however, not been given final regulatory approval at this stage, and may also not be applied to all available sea basins susceptible to host OBZs. The main take-away is that Flow-Based capacity calculation is a more dynamic but accurate representation, which makes it more difficult to measure the true impact of transmission risk on both the level of market curtailment to

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<sup>14</sup> Based on an NTC modelling of the DAM for a meshed offshore grid in the North Sea under a net-zero scenario (High Wind from ProMotion project).

<sup>15</sup> Under FB, loop flows in the system can locally enlarge the transmission capacity available in their opposite directions.



be expected for the offshore wind production, and on the OBZ price. The latter may indeed not always align on the cheapest neighboring onshore bidding zone under this methodology<sup>16</sup>

Regardless of the network representation, OBZs feature a more acute sensitivity to transmission capacity. This conclusion stems from both the characteristics of smaller bidding zones and that of the hybrid system itself. Therefore, **we must assess more specifically which situations (transmission reduction events) would lead to a discriminatory treatment of offshore renewable energy in dedicated OBZs. Indeed, it is only these situations that would justify the redistribution of congestion income back to specific generators.** This is the purpose of the next section.

### 3.4. Transmission risk: what situations, what discriminations?

As discussed, the strong correlation between the OBZ dynamics, the grid topology and the level of transmission capacity is probably their most distinguishing aspect. As a result, the exposure of the offshore generator to reduced transmission capacity (below nominal value) can have beyond-ordinary impacts on its revenues. However, not every such situation of lowered transmission is equal in terms of duration, legal responsibility and justifies a dedicated compensation scheme. More precisely, we identify below five main categories listed in order of decreasing duration:

- **Coordination issues between grid and generation planning:** this could lead to transitory under-dimensioned periods. While this is rather unlikely to be a major issue with an appropriate investment planning (cf. new coordinated planning rules under the revised TEN-E Regulation and ENTSO-E's TYNDP), one cannot exclude practical implementation challenges, which could suppress export capabilities and OBZ prices for the mid-term due to the inertia of such projects. Issues can occur if the development of the transmission capacity takes more time than expected, or if it has finite sizes and cannot be adjusted marginally ("lumpiness"), etc.
- **Force majeure & emergency:** this happens when transmission is fully or partially out of service due to exceptional circumstances. Force majeure specifically refers to "*any unforeseeable or unusual event or situation beyond the reasonable control of a TSO*" (Art 2.45 of CACM regulation), e.g. several cables ripped off by an extreme weather event, even though the NRA must in practice validate what qualifies as force majeure. Meanwhile, emergency is said to occur when "*the transmission system operator must act in an expeditious manner and re-dispatching or countertrading is not possible*" (Art. 16.2 of EU Regulation 714/2009). Due to the difficulties to perform repairs at sea, a complete loss of an HVDC offshore cable takes on average two months to resolve (ENTSO-E and EUROPACABLE, 2019). Different financial regimes may apply in either cases, as set out by Art. 72 of CACM Regulation:
  - No compensation to generators for either situations in the case of capacity allocated implicitly (DAM, IDM);
  - Compensation to generators at purchased price under force majeure in the case of capacity allocated explicitly (LTTRs);
  - Compensation at contract value to generators under emergency in the case of capacity allocated explicitly (LTTRs).

In practice, the exact rules should be defined in the connection contract with the TSO and the associated risk be considered by all assets for the investment decision, regardless of their technology and situation.

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<sup>16</sup> Under FB, (hybrid) exchanges can be restricted by remote and not just direct network elements. When this happens, the price is set as the marginal value of the most restricting element, wherein power from remote zones may be flowing. As such, the OBZ price does not always correspond to the neighboring price signal.

- **Line maintenance & upgrades:** Maintenance can typically be required on a yearly basis for electric reliability reasons. The transmission capacity may be partially or fully unavailable for a mean duration of one week. When this is a planned activity, TSOs generally optimize and publish their maintenance schedule a couple of months ahead. As the wind generation cannot be forecasted accurately over such horizons and no power sink is typically available on-site to mitigate the absence of export possibilities, it is typical for renewable assets to align their own maintenance schedule on these periods. Some maintenance work may be unplanned but here once again, the conditions for compensation are usually laid out bilaterally between the involved assets and the TSO in the connection contract.
- **Limited interconnection capacity provided to the market (operational deratings).** In this situation, the entire transmission capacity may be in service, but is not fully released to the market. Although in principle the allocation should be maximal, TSOs must fulfill their duty to ensure system reliability, which may lead to them derating some cross-zonal capacities as part of the general capacity calculation process. This is a form of preventive congestion management which are targeted at addressing the inherent imperfections of the zonal model (e.g. internal loop flows, DC approximation, etc.), and information incompleteness at the time of the forecast (e.g. uncertainties in weather expectations). The terms under which these actions can be performed are dictated in the Capacity Calculation Methodology (CCM) of each market timeframe. Depending on the exact issue, the reduction may be effective for one hour to as long as several days. The current regulatory target is to aim for at least 70% of the cross-zonal capacity to be allocated to the market (Art. 16 EU Regulation 943/2019). Conversely, deratings for reliability reasons should not exceed 30%. In the case of OBZs, the causes mentioned above may not apply as it should in theory be a full DC system with no internal congestion.
- **Reduced capacity through (cross-border) redispatching:** After the market has cleared and despite preventive deratings, there may still be situations where the physical network cannot accommodate the dispatch schedule at delivery. In such instances, TSOs may resort to curative congestion management actions, including redispatching and costly remedial actions. The offshore generator may be instructed to regulate downwards, and/or the transmission capacity may be reduced in the export direction to solve congestion elsewhere. However, in theory, the impacted assets should be made financially independent from redispatching in order to prevent gaming strategies. Therefore, the offshore generator is treated no differently than any other asset and redispatch measures should not represent a risk for its business model. Further, actions taken via the balancing mechanism are in generally very short-term (maximum a few hours).

Summing up, while transmission capacity reduction events represent a serious risk for the economics of offshore renewable energy located in the OBZ, it turns out that many of such situations are already addressed by the current regulatory framework, except operational deratings. We summarize our findings in Table 3.

Transmission reduction case	Measure to address the issue ?	Discriminatory treatment vs. onshore technologies?
<b>Uncoordinated grid and generation planning</b>	Reinforced coordination – grid first, then generation.	<b>No</b>

<b>Force majeure &amp; emergency</b>	To be defined in access rules of the connection contract with TSOs	<b>No</b>
<b>Line maintenance</b>	To be defined in access rules of the connection contract with TSOs	<b>No</b>
<b>Limited interconnection capacity provided to the market ("operational deratings")</b>	Redispatch for onshore BZs and full market risk for generators in OBZs	<b>Yes</b>
<b>Redispatched capacity</b>	The redispatch mechanism should make all participants financially neutral	<b>No</b>

**Table 3 Cases of transmission capacity reductions in OBZ**

A level-playing field is already provided for force majeure & emergency, maintenance and redispatched transmission capacity, while the remaining issues are the possible delays in transmission expansion and the reduced capacity allocation to the market.

In the case of uncoordinated grid and generation expansion, the measures in place do not discriminate OBZs per se, but the financial implications of such a situation would be more damaging than for assets located in onshore BZs. If an interconnector is delayed, there is simply no congestion income collected and redistribution methodologies would therefore not be an appropriate mitigation tool. Ensuring tight coordination and establishing the OBZ only when the entire system is set up is probably the sounder alternative.

The utilization of operational derating for hybrid cross-zonal transmission capacity provided to the market, on the other hand, clearly creates differential treatment. For assets located onshore, there is no derating because the transmission capacity is intrazonal and not given to the market. On the other hand, deratings could be applied on hybrid transmission links, while the underlying justifications may not apply for dedicated OBZs given the absence of internal congestion in such systems. If deratings are applied, it is therefore to account for the effect of congestion elsewhere in the system. Besides, even though the current allocation target is a minimum of 70%, it is not always guaranteed in practice as 1) some TSOs already benefit from derogations and 2) further deratings are still legally possible for reliability reasons in period of system stress.

### **3.5. Concluding remarks on the need for dedicated support**

Dedicated OBZs are the most efficient and future-proof way forward for the integration of offshore renewable assets. Dispatching and balancing in the OBZ drive higher operational security, since transmission constraints are integrated preventively. Also, a more granular pricing improves signals for consumption and investment (e.g. storage and hydrogen facilities).<sup>17</sup>

Besides, this leads to an economic surplus redistribution . whereby TSOs now justly recover the value of transmission on the hybrid links that would have otherwise been internalized into the energy value of the reference Bidding Zone. In other words, the TSOs typically raise higher levels of congestion income while the generators' surplus in the OBZs is reduced, because the dispatch is no longer "blind" of underlying transmission restrictions. This is not an issue per se, as it is the consequence of an efficient price setting.

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<sup>17</sup> Directorate-General for Energy. Laur, A. & Küpper, G. (2021): "Smaller bidding zones in European power markets: liquidity considerations". Study developed as part of the ASSET project by ENGIE Impact.

Moreover, the need for costly redispatch actions is also reduced which, all things equal, will lower the transmission tariff in the electricity bill of the final consumer.

Still, dedicated OBZs clearly induce shifts in the risk profile faced by each stakeholder. In particular, it accentuates the economic impact of the transmission externality for the offshore generator. This impact can concretely materialize in lower prices and market-based curtailment when transmission is particularly scarce, which can occur in different, more or less transitory situations. We analysed what situations would represent a clear market failure or a discriminatory treatment of offshore generation in dedicated OBZs, so as to determine whether support should come from the redistribution of congestion income to specific generators. Our conclusion is that “operational deratings” of transmission capacity by TSOs represents the single major transmission-related barrier to creating a level-playing field between offshore and onshore generation assets. This barrier could be addressed with or without a link to congestion income. Meanwhile, the other situations may be impactful but do not attest of any mistreatment of hybrid projects and do not justify redistribution of congestion income.

In fact, any support based on the redistribution of an efficiently-allocated CI should indeed be aimed at addressing specific market shortcomings and cannot be justified on the sole basis of securing the merchant investment for a subset of producers. While the uncertainties related to OBZs are certainly difficult to estimate for the offshore generator and can undermine the investment decision, redistributing surplus to cover the OWF business case would be discriminatory against similar assets. Potential barriers to investment include: . problems both of revenue level (total income insufficient) and/or of revenue volatility (short-term variations due to market dynamics), although the access to multiple markets can somewhat mitigate this aspect. In such cases, adequate hedging and possibly further (traditional) support may be necessary to ensure the successful deployment of hybrid projects at scale.

Past studies such as (THEMA Consulting Group, 2020) or (ENTSO-E, 2021) have already discussed a number of congestion income (CI) redistribution options, without specifying further the precise transmission risk that is currently untreated (operational deratings). In the next section, we study 2 of these options in more detail: the-so called “CI-FTR” and “CI-CfD”.

## **4. DEDICATED SUPPORT OPTIONS FOR HYBRID OFFSHORE DEVELOPMENT**

The past section discussed the increased risk exposure of offshore generators under dedicated OBZs and why it may be desirable from a system perspective to further support these projects in order to reap the associated benefits of offshore development and market integration. This section thus studies several bespoke arrangements, their modus operandi, their suitability and their legal implications.

### **4.1. Previous studies on congestion income redistribution**

Past studies such as (THEMA Consulting Group, 2020) or (ENTSO-E, 2021) have already discussed a number of congestion income (CI) redistribution options. In general, since the very concept of CI redistribution is not foreseen in the current legal framework (cf. Section 1, CI must be used first to self-regulate), it is clear that these options all require different degrees of regulatory changes. While some were found to require only modest integration efforts, others appeared in direct contradiction of fundamental EU principles and were found as such quite unrealistic.

For the sake of conciseness, the detailed descriptions of these options (alongside some quantifications where possible) can be found in Appendix 1. We provide below an overview of the most relevant aspects of our analysis:

Option name	Concept	Pros	Cons
<b>Congestion Income Contract for Differences (CI-CfD)</b>	Redistributes price spread to reference BZ x Offshore prod, possible pre-allocation	<ul style="list-style-type: none"> <li>• Full asset lifetime covered</li> <li>• Hedge with reference BZ even without direct connection</li> </ul>	<ul style="list-style-type: none"> <li>• Competes against existing LTTR instruments</li> <li>• As-produced: curtailment risk not fully covered</li> </ul>
<b>Congestion Income Financial Transmission Rights (CI-FTR)</b>	Redistributes price spread to reference BZ x fixed volume, possible pre-allocation	<ul style="list-style-type: none"> <li>• Hedge with reference BZ for a fixed volume</li> <li>• Already existing product, only offshore generator pre-allocation to be determined</li> </ul>	<ul style="list-style-type: none"> <li>• Requires direct connection to reference BZ</li> <li>• 1-year delivery period maximum for now</li> </ul>
<b>Congestion Income Auction Revenue Rights (CI-ARRs)</b>	Redistributes share of LTTR forward sales revenues	<ul style="list-style-type: none"> <li>• Ex-ante lump sum payment</li> <li>• Can be converted back into FTRs (self-scheduling)</li> </ul>	<ul style="list-style-type: none"> <li>• Support level decorrelated from actual contributions to CI</li> <li>• Adverse incentives (to raise auction prices)</li> </ul>
<b>Congestion Income Direct Reallocation</b>	Redistributes marginal contribution to CI over hybrid links	<ul style="list-style-type: none"> <li>• Direct contribution to CI on surrounding links reimbursed</li> </ul>	<ul style="list-style-type: none"> <li>• Complete (re)allocation methodology to establish legally</li> </ul>
<b>Joint ownership model</b>	TSOs and generators co-own the hybrid system	<ul style="list-style-type: none"> <li>• Custom cost sharing agreements can be set up</li> </ul>	<ul style="list-style-type: none"> <li>• Third-party access is an issue</li> <li>• Against unbundling</li> </ul>

**Table 4: Overview of CI redistribution options**

In summary, the Joint Ownership and CI-ARR options appear to be the furthest away from current regulation. The **Joint Ownership** would in effect require TSOs to have a direct stake in generation assets, which goes against the unbundling principle. Meanwhile the **CI-ARR** is a concept imported from US systems whose implementation would be difficult to justify in an EU context where the forward market drastically differ by design. Further, the CI-ARR does not guarantee any minimum level of support and does not directly address the issue of reduced transmission capacity allocation. Lastly, the **Direct CI Reallocation** implies defining a complete methodology to define which flows “belong” to the offshore generator so that the associated CI can be transferred back by TSOs. Although the idea of marginal redistribution is interesting, the calculation may become quite complex in practice, especially when considering multiple CCRs under different network representations, or multiple offshore generators in a meshed topology. In addition, this mechanism would occur based on market scheduled flows, which means that the market curtailment risk due to reduced transmission allocation is not mitigated.

After considering all relevant aspects, the Joint Ownership, the CI-ARR and the Direct CI Reallocation mechanisms have thus been excluded from the remaining analysis. we review therefore 2 of these options in more detail: the-so called “CI-FTR” and “CI-CfD”.

## **4.2. Option 1: Congestion income redistribution by free allocation of FTRs (CI-FTR)**

In the interest of timely setting up a support mechanism, and considering that such support mechanisms are more relevant in the short term than in the long term, it may be more sensible to rely on already existing arrangements – at least partially – rather than building entirely new legal segments from the ground up. In particular, Long-Term Transmission Rights (LTTRs) were shown to be the only active contracts designed specifically to redistribute congestion income. Their financial variant – Financial Transmission Rights (FTR) – show superior economic properties and allow participants to hedge the locational risk between two neighboring BZs and in a specific direction. TSOs normally auction these contracts forward and remunerate the holders at the price spread when the latter is unfavorable. The free allocation of FTRs to offshore generators located in an OBZ would shift the associated congestion income from TSOs to offshore generators. This is what we propose under the “**CI-FTR**” appellation.

More concretely, one could consider a pre-allocation round where some LTTR capacity would first be reserved to offshore renewable energy projects before auctioning the leftover to other market participants. This ex-ante distribution could possibly be part of the competitive tender whereby connection contracts are awarded (at investment decision level). As such, assets that successfully secured their connection to the offshore grid would be granted a volume of CI-FTRs to be potentially renewed over several delivery periods for a total duration determined by NRAs. One of the main concerns lies with the delivery period, which currently does not go beyond the yearly timeframe and would as such require a reallocation at regular intervals. Also, to keep the working of the mechanism as simple as possible, a reference BZ needs to be pre-defined. A proposal for such reference BZ would be the onshore BZ related to the terminal of the hybrid asset in the country of the Exclusive Economic Zone. The amount of CI-FTRs allocated is another parameter that needs to be defined. A first natural choice would be a quantity corresponding to the installed net generation capacity of the offshore generation asset (wind farm).

However, as the network grows and becomes more meshed with potentially multiple OBZs associated to the same reference onshore bidding zone, it may occur that the transmission capacity towards that reference becomes insufficient to cover the entire generation capacity of those wind assets (the remainder of the transmission necessary to evacuate the power being directed to other zones). Since FTRs are in principle capped by the transmission capacity, then the CI-FTR reallocation rounds would either need to allocate the capacity pro-rata (thereby progressively reducing the ratio of capacity hedged for each asset), or define new references for new investments to continue ensuring full support.

## **4.3. Option 2: Congestion income redistribution by free allocation of CfDs (CI-CfD)**

The other type of existing contract that would incorporate this longer-term characteristic is the Contract for Differences (CfD). Traditionally, CfDs are signed through a tenderized process between governmental bodies and certain categories of generators. They enable the winners to secure a fixed “strike” price for their production that is agreed by regulators or Member States, thereby removing any price uncertainty. The CfD contract could be reconditioned to introduce the onshore (reference) BZ price as a variable strike. With the TSO as counterparty, the design of this new “**CI-CfD**” would permit the long-term redistribution of the price spread OBZ-onshore reference BZ for every unit of energy produced. As regards the quantity of CI-CfDs to be allocated, one could consider quantities “as-produced” or a pre-defined volume (in which case the mechanism is similar to a CI-FTR). As mentioned in section 4.1, a more exhaustive description of the instrument is provided in Appendix.

## 4.4. Assessment of the retained options

### 4.4.1. Evaluation criteria

Section 3 concluded that operational deratings represent the single major transmission-related barrier for offshore generators in an OBZ, potentially justifying a redistribution of congestion income from TSOs to offshore generators. In view of providing recommendations on the way forward, we evaluate the options identified so far according to the following criteria:

- Investment incentives: the solution must contribute to lower the risk related to the investment and operation of an offshore generation asset in an OBZ setup.
- Alignment with previous policies and with the current legal framework: options may typically be easier to agree on and to implement if they do not deviate too much from the status quo. This criterion therefore considers the extent to which the various options are considered in the current legal framework.
- Scalability: the solution must work at scale, with a large set of hybrid projects in the EU power system. For instance, the option needs to be standardized easily and coordination between different TSOs should be manageable. More globally, we believe that similar questions arise when defining smaller bidding zones, which can be expected in a system increasingly dominated by intermittent wind and photovoltaics generation spread across the country.
- Robustness: the solution must work over time with evolving market conditions (price dynamics, bidding zone adjustments, grid reinforcement).
- Eligibility: is the measure directed to hybrid projects and to the identified problem?
- Optionality: the solution must provide project developers with a choice rather than a mandatory and unique pathway (possibility to opt-out).

The assessment will rank the proposed options and lead to a recommendation for the best measures and the way forward.

### 4.4.1. Assessment of CI-FTRs and CI-CfDs

The assessment of the LTTR options (CI-FTR & CI-CfD) following the criteria described earlier is provided in Table 5. Both options fully hedge against the locational price risk and the reference BZ price becomes the true reference price for the offshore generation. In principle, long-term contracting over several years should be possible, although today the allocation of FTRs typically does not exceed 1 year. Altogether, investment incentives are expected to be improved although **CI-FTRs and CI-CfDs do not necessarily avoid the necessity for a direct (traditional) support mechanism** to unlock investment. Indeed, while the latter are typically devised to secure a revenue floor based on the Levelized Cost of Electricity (LCOE), the former would provide a top-up to merchant revenues without necessarily guaranteeing an absolute level. In fact, it is not guaranteed either that the average reference (onshore) price exceeds the offshore generator's LCOE in the long run. This also implies that the investment case is not guaranteed either for assets directly developed within an existing onshore bidding zone. **Neither the CI-FTR nor the CI-CfD ensure revenue adequacy for the TSO(s) operating the reference hybrid interconnector if/when the contract volume (installed capacity or production, respectively) exceeds the capacity of the cable.** In this case, the congestion income collected by the TSO would be lower than the payments to offshore generator when compensation is due. The interconnector's profitability thus decreases and the TSO has less revenues at its disposal for new investments and network tariff mitigation, unless the



savings entailed by the OBZ design (such as on remedial actions) can offset the difference. However, this conclusion is only valid when the asset is taken in isolation. In our quantification (cf boxes in Appendix), we found that for the described case, the redistributed CI ranged between 37 and 68% of the total CI collected across *both* links in the hybrid system. This indicates that the hybrid system *as a whole* could remain revenue adequate, and that a positive business case could be achieved for all parties if TSOs engage in sharing agreements, by for example taking a joint ownership in all hybrid links rather than full ownership on their respective “side”. Besides, even without specific bilateral agreements, current cost sharing mechanisms could allow for socialization of this deficit across profitable borders from the same CCR.

The CI-CfD “as-produced” embeds an important drawback: it does not address dispatch restrictions resulting from operational deratings. In other words, if the derating of hybrid links forces the offshore generation below its potential, the CI-CfD does not compensate for it directly with its volume component (although it may indirectly through its price component which would show larger spreads). Since operational reduction of cross-zonal capacity has precisely been identified as the single discriminatory transmission event for offshore generators, it appears challenging to justify of its suitability in this case. As a last consideration, the features of this new CI-CfD would also de facto require the contract to be considered as an alternative form of LTTR, which is not the case in the current legal framework. The design of a new LTTR could be challenging, as it would need to be coordinated with the already existing FTR mechanism (two instruments competing for the same underlying capacity and CI, liquidity split, complexified FTR capacity forecasts for TSOs, gaming, etc.). Among LTTR options, the CI-FTR mechanism seems therefore to be the preferred option. From a policy perspective and to maximize the potential of the option, it is important that the forward market for FTRs is made as liquid as possible, that the capacity put for sale is maximized by an efficient and coordinated calculation methodology, and that the delivery period is extended to reduce the need for frequent reallocation (Laur & Küpper, 2021). In this regard, it should be noted that the FTR delivery period would in any case not be extendable to the asset lifetime like the CI-CfD (but rather to a handful of years) due to the overly large uncertainty related to network development and capacity calculations over horizons beyond the TYNDP scope. A liquid market for LTTRs is especially relevant to counterbalance the effects of the free allocation, which would reduce the capacity put up for sales to all participants in forward rounds. Although no legal changes are required for the FTR product itself, the new (free) allocation phase would on the other hand necessitate amendments of the Forward Capacity Allocation Guideline (FCA Reg., Commission Regulation (EU) 2016/1719). Via the current regulation, long-term cross-zonal transmission rights should be allocated to market participants via central auctions, organized by the single allocation platform JAO. The new free allocation phase would need to be done before the JAO auctions. A free allocation is currently not foreseen by the FCA Reg..

One important aspect of the proposed options 1 and 2 is that they cannot only be targeted at situations of operational deratings. As a matter of fact, the holder of the CI-FTR or CI-CfD (i.e. the offshore generator) gets remunerated whenever the price of the reference BZ is higher than the OBZ price, not solely when operational deratings are applied. The offshore generator may therefore receive an overcompensation for the identified problem. This raises several important issues:

- The mechanisms are difficult to scale-up, since increasing amounts of CI have to be shifted from TSOs to offshore generators if more hybrid projects are implemented, which may endanger revenue adequacy of regional TSOs. This may also provide disincentives to the TSOs to propose hybrid infrastructure projects (and to ENTSO-E in the Strategic offshore network development plans);
- Eligibility to the mechanisms might be an issue: assets located in “smaller” onshore bidding zones could be discriminated and may claim to be treated in the same way and defining eligibility criteria may therefore prove complex;



- The mechanisms represent a non-transparent way of supporting offshore renewable energy. There is no clear reason why CI should be used to support offshore renewable energy. Traditional, direct support mechanisms provide information on the support cost more transparently;
- With more hybrid projects, TSOs will have to shift increasing amounts of CI that they will have to be compensated by higher grid tariffs. The national discussion of increasing grid tariffs tends to be challenging, as so it can be having support schemes for renewables in place. With a shift that has impacts on tariffs instead of state aid, the public support is moved from taxpayers' to consumers' contributions and may result in a delayed investment on the necessary offshore grids. Therefore, any shifts of congestion income needs to be proportional and limited to the barriers identified in this report. Moreover, a large-scale deployment of CI-FTRs or CI-CfDs will tend to increase the relative importance of grid charges in the final electricity tariff, thus rendering demand side flexibility (where only the commodity price can be recovered) less attractive.
- The mechanisms should be phased out if smaller BZs are defined or if grids are reinforced in the future. Operational deratings should occur less and less. However, the proposed contracts according to Options 1 and 2 do not phase-out by design and it might be difficult to abolish them as it shifts potentially large amounts of revenues to offshore generators.
- Finally we remind that these options do not necessarily avoid the necessity for a direct (traditional) support mechanism to unlock investment. Indeed, the support is not intended to permanently secure above-LCOE levels of remuneration, but will rather evolve dynamically based on future market conditions. As such, the business model will remain merchant and conditional on macro factors such as technological costs or borrowing rates. For these reasons, we conceptualized a third option in the course of this report: the Transmission Access Guarantee (TAG), which is presented and evaluated in the next section.

Criterion	CI-FTRs	CI-CfDs
<b>Investment incentives</b>	<ul style="list-style-type: none"> <li>• The support is contracted with the TSO at investment decision level</li> <li>• The locational risk is covered, not only in case of preventive congestion management</li> <li>• The volume is fully defined, independent from the production level</li> <li>• Long term contracting is possible through reallocation (duration to be defined)</li> <li>• The contract value follows the market spread and can therefore be volatile. A direct support mechanism (or PPA) might still be needed (<math>\sim</math>Long Run Marginal Cost – OBZ revenue – value FTRs)</li> </ul>	<ul style="list-style-type: none"> <li>▪ The support is contracted with the TSO at investment decision level</li> <li>▪ The locational risk is covered, not only in case of operational deratings</li> <li>▪ The volume risk depends on the way volumes are defined (fixed or as-produced)</li> <li>▪ Long-term contracting is possible (duration to be defined)</li> <li>▪ The contract value follows the market spread and can therefore be volatile. A direct support mechanism (or PPA) might still be needed (<math>\sim</math>Long Run Marginal</li> </ul>

Criterion	CI-FTRs	CI-CfDs
		Cost – OBZ revenue – value CfDs)
<b>Alignment with previous policies</b>	<ul style="list-style-type: none"> <li>• “Classic” FTRs exist in the current legal framework (FCA Reg.), but not freely allocated</li> <li>• Firmness might be an issue, if amount of CI-FTRs exceeds the capacity of the cable specifically connected to the reference BZ</li> <li>• A Reference BZ has to be defined</li> <li>• Long term allocation is currently not standard (<math>\leq 1</math> year)</li> </ul>	<ul style="list-style-type: none"> <li>▪ CI-CfDs are de facto LTTRs, but the legal framework does not consider such contracts</li> <li>▪ Firmness might be an issue, if amount of CI-CfDs exceeds the capacity of the cable.</li> <li>▪ A Reference BZ has to be defined.</li> </ul>
<b>Scalability</b>	<ul style="list-style-type: none"> <li>• The mechanism should be designed as simple as possible (pre-defined permanent Reference BZ).</li> <li>• TSOs must set up a coordination structure with JAO to inform pre-allocated volumes to be discounted from FTR auction.</li> <li>• The mechanism is not only targeted at operational deratings. The offshore generator is therefore overcompensated. TSOs will have to shift increasing amounts of CI, with possible distortions of the final electricity tariff.</li> </ul>	<ul style="list-style-type: none"> <li>▪ The mechanism should be designed as simple as possible (pre-defined Reference BZ, same as for CI-FTRs).</li> <li>▪ TSOs must set up a coordination structure with JAO to inform pre-allocated volumes to be discounted from FTR auction. As CI-CfD is double-sided, they must also ensure OWFs are liquid (collateral requirements)</li> <li>▪ The mechanism is not only targeted at operational deratings. The OWF is therefore overcompensated. TSOs will have to shift increasing amounts of CI, with possible distortions of the final electricity tariff.</li> <li>▪ The mechanism would need to be coordinated</li> </ul>

Criterion	CI-FTRs	CI-CfDs
		with the FTR allocation mechanism.
<b>Robustness</b>	<ul style="list-style-type: none"> <li>The offshore generator is hedged against topology changes. The Reference BZ is always the reference market.</li> <li>The mechanism is phasing out (or should be phased out) if smaller BZs are defined in the future. Operational derating should occur less and less, but it might be difficult to abolish the measure.</li> </ul>	<ul style="list-style-type: none"> <li>The hybrid asset is hedged against topology changes. The Reference BZ is always the reference market.</li> <li>The mechanism is phasing out (or should be phased out) if smaller BZs are defined in the future. Operational deratings should occur less and less, but it might be difficult to abolish the measure.</li> </ul>
<b>Eligibility</b>	<ul style="list-style-type: none"> <li>New onshore renewable projects located in "small" BZs may face similar risks and could oppose eligibility restrictions to offshore only</li> <li>Potential State aid issue</li> </ul>	<ul style="list-style-type: none"> <li>New onshore renewable projects located in "small" BZs may face similar risks and could oppose eligibility restrictions to offshore only</li> <li>Potential State aid issue</li> </ul>
<b>Optionality</b>	<ul style="list-style-type: none"> <li>The offshore generator can resell the FTRs and choose another hedging strategy.</li> </ul>	<ul style="list-style-type: none"> <li>The CI-CfD is asset-specific (linked to assets located in the OBZ). The OWF cannot swap the CI-CfD with another contract.</li> </ul>

**Table 5 Assessment of CI-FTRs and CI-CfDs**

#### **4.5. Option 3: the Transmission Access Guarantee (TAG)**

The Transmission Access Guarantee (TAG) refers to a new support alternative, which has been conceptualized in the course of this report. We first present and then evaluate the concept.

##### *4.5.1. Presentation of the TAG*

As discussed extensively in section 3, the offshore generators' revenues are heavily conditioned by the availability of enough transmission capacity in the hybrid system. We showed that, if the hybrid system is structurally well designed and planned, most transmission reduction events already come with compensations to mitigate that risk. The only exception, however, is the case of reduced capacity allocated to the market. These operational derating measures are normally performed to strike an effective balance between maximizing cross-zonal capacity and ensuring system reliability at least-cost. We argued that there should in theory be no need for such actions in the case of standalone OBZs, because the hybrid system itself should feature no internal congestion. Indeed, as shown in Appendix 2, the ideal assumptions of bidding zones should in fact be respected under OBZs in the sense that there should be no structural congestion nor internal loop flows (congestion may happen within the wind farm itself but this would be before the main grid connection point and thus remains the wind operator's responsibility). What's more, the hybrid links should be implemented as HVDC cables which means they are fully

controllable and do not suffer from the uncertainty related to AC elements and their simplified representation.

In summary, if the hybrid system is designed in such a way that the entire wind production can structurally be exported onshore and also features no zonal uncertainty, then it should be ensured that such a property is reflected in the market clearing. Conversely, reduced export capabilities for the hybrid links can only be the result of zonal uncertainty elsewhere in the system. Such operational restrictions would serve to preventively alleviate congestion elsewhere, where the affected generation assets are already less exposed to the transmission risk. For these reasons, it would appear justified to guarantee transmission access for the full offshore transmission capacity: this is the TAG. More precisely, the TAG would set a target to ensure that **the total export capability of the OBZ is always greater than or equal to the total net installed offshore renewable generation capacity**. In instances when this target cannot be achieved for operational reasons, a compensation mechanism would then be set up for the offshore generator to recover the missed-out revenues it would have collected in a reference market. The compensation would be calculated as follows:

*TAG compensation = Max(Reference bidding zone price – OBZ price, 0) x total offshore generation available.*

This compensation would be paid for by the TSO(s) responsible for restricting network elements. As such, TSOs have the incentive to only curtail transmission when the associated system benefits outweigh the offshore generators' opportunity costs.

The TAG should therefore stabilize the offshore generators' revenues, while avoiding to endanger system reliability since curative measures can still be employed (such as curtailment of the offshore generation during balancing, against compensation). This has the advantage to be simple, transparent and directly targeted at the issue.

The described TAG rule would be suitable for all network representations:

- Under the **NTC representation**, the export capability of the OBZ is simply the sum of the available transfer capacities (ATC) over all hybrid interconnectors in the export direction. The compensation thus activates if the ATC values provided to the market clearing algorithm do not amount to at least the wind installed capacity. If multiple derated ATCs are involved, the compensation should be borne by their associated TSOs in proportional weights.
- Under the **Flow-Based representation**, the "true" export capability of the OBZ is not only determined by the Remaining Available Margins (RAMs) of the hybrid links, but rather by the most restricting constraint of all Critical Network Elements (CNEs) in the Flow-Based domain. The maximum net exchange position can be simply calculated by optimization (maximization of the OBZ export with respect to the Flow-Based constraints). The compensation thus activates when the Flow-Based domain does not contain a clearing point through which the full wind capacity can be exported. Note that TSOs are already performing and publishing such a calculation of maximum export and import limits per Bidding Zone on an operational basis. If multiple CNEs are involved, the compensation is borne proportional to the individual contributions (possibly in a similar fashion to the redispatching cost sharing arrangements, see (ENTSOE, 2020)). Although in theory a remote TSO could be requested to compensate for an indirect hybrid capacity reduction, in practice, the most restricting CNEs for the export of a certain BZ are usually located in its vicinity. Thus, it is the local TSOs that should be the most concerned with ensuring the TAG target.

With Flow-Based, one additional aspect to consider is the possible impact of the **Advanced Hybrid Coupling (AHC) approach**, which should be deployed as an additional layer where the FB representation is in use. Under AHC, the HVDC interconnectors can be modelled by up to two explicit virtual hubs (one at each extremity) and an ATC link to connect them. The virtual hubs are included in the PTDF matrix to account for the impact of loading the HVDC link on surrounding elements, while the ATC link represents the controllable flow through the physical interconnector. In this approach, both the ATC link and the net positions of the virtual hubs should be capped by the nominal capacity of the HVDC interconnector. In other words, with AHC, 100% of the physical capacity is already provided to the market under normal conditions. More precisely it may shift the possible network restrictions from preventive measures to endogenous constraints: the margins (RAMs) given to the market as inputs are no longer derated to account for the HVDC loading, but the PTDF coefficients associated to the virtual hubs may then reduce the maximum exchange position of the OBZ from within the market clearing algorithm.

AHC brings system-wide benefits and fosters stronger market integration and efficiency by internalizing the transmission deratings on HVDC links inside the market clearing algorithm. This effect - although not quantified yet - is expected to result in larger Flow-Based domains, which means that the TAG target should be respected statistically more frequently. From that point of view, the TAG can be seen as a safeguarding measure, in case AHC is not implemented or does not deliver the expected results. On the other hand, should this target not be met, it could become more complex to define the marginal contributions of specific elements to the reduction of the OBZ export capability, and how to share the due compensation across involved TSOs. In this case, one possibility would be to assess whether the Virtual Hubs representing the connection points of the hybrid HVDC cables also enable a cumulated maximum export capability at least equal to the installed offshore generation capacity. In principle, the Virtual Hubs should only represent the impact of the transmission constraints since their prices are formed from the dual values (a.k.a "shadow prices") of the Flow-Based constraints. Dual values are a byproduct of the market clearing algorithm and indicate the marginal impact of the CNE limits on system welfare.

#### 4.5.2. Evaluation of the TAG

The TAG tackles the risk at the source, by defining a compensation paid by the TSO to offshore generators if the latter face transmission capacity reductions as a result of preventive congestion management. As opposed to options 1 and 2, the TAG therefore does not entail overcompensations and related issues.

Criterion	TAG
<b>Investment incentives</b>	<ul style="list-style-type: none"> <li>▪ The TAG only compensates for preventive congestion management. The OBZ remains the reference market. "Classic" FTRs can be bought to hedge against locational risk.</li> <li>▪ As with other options, a direct support mechanism (or PPA) might still be needed.</li> </ul>
<b>Alignment with previous policies</b>	<ul style="list-style-type: none"> <li>▪ The current legal framework does not foresee such compensation. A structure would have to be defined for the practical implementation of the mechanism, with new roles and responsibilities of stakeholders (esp. NEMOs and NRAs).</li> <li>▪ The allocation of the costs among TSOs becomes more complex if AHC is implemented. An allocation mechanism would have to be defined.</li> </ul>
<b>Scalability</b>	<ul style="list-style-type: none"> <li>▪ Ensured, as no coordination needed with LTTRs.</li> </ul>

<b>Robustness</b>	<ul style="list-style-type: none"> <li>▪ The compensation is limited to the case of preventive congestion management.</li> <li>▪ The TAG does not hedge against topology changes. "Classic" FTRs will have to be bought to this end.</li> <li>▪ The mechanism is automatically phased out if smaller BZs are defined in the future. Operational deratings should occur less and less.</li> </ul>
<b>Eligibility</b>	<ul style="list-style-type: none"> <li>▪ OBZ do not exhibit internal congestion. The full cross-zonal transmission capacity should be provided to the market. It is therefore easier to limit the mechanism to offshore renewable generation located in a OBZ.</li> </ul>
<b>Optionality</b>	<ul style="list-style-type: none"> <li>▪ Offshore generators receive a monetary compensation and can use the money for other purposes.</li> </ul>

**Table 6 Assessment of the TAG**

Compared to CI-FTR and CI-CfD options, the OBZ remains the reference BZ and this requires a well-designed FTR mechanism to hedge the increased locational risk adequately. The TAG mechanism is phased-out by design: if intra-zonal congestions disappear (by defining possibly smaller BZs or reinforcing the grid), the TAG compensation will not be triggered. Finally, the TAG mechanism would have to be foreseen in the legal framework. More details on this aspect are provided in Section 5.

## **5. REGULATORY IMPLICATIONS OF THE OPTIONS CONSIDERED**

In order to further assess the effort in the implementation of the proposed options 1, 2 and 3, a review of the required changes to the relevant network codes has been performed. The analysis includes the FCA GL, CACM, Electricity Regulation 2019/943 and the Renewable Energy Directive II (REDII) and the main results are presented in Table 7. The table showcases which existing articles may conflict with the proposed measures, and which ones simply require amendments. Of course, additional articles to detail the methodology of the chosen option may also be required and are not referenced here.

It comes with no surprise that the CI-FTR and CI-CfD mostly necessitate amendments of Article 19 from the Electricity Regulation 2019/943 and of the FCA GL, which oversees the forward allocation process. Indeed, both would conflict with one of the aims of that regulation, as stated in article 3 (point c); the provision of "non-discriminatory access to long-term cross-zonal capacity", resulting then in a conflict also with the general principles exposed in article 28. On top of that, the CI-CfD conflicts with several segments related to product design (articles 31, 35, 43 and 44). The CI-CfD conflicts also indirectly with the article 73 of the CACM defining the requirements for the methodology for sharing congestion income, as this article would need to be updated with the CI-CfD concept. Finally, it must be emphasized that both the CI-FTR and the CI-CfD conflict with the article 9.2 of the Electricity Regulation stating that "long-term transmission rights shall be allocated in a transparent, market based and non-discriminatory manner through a single allocation platform".

Conversely, the TAG relates to operational capacity calculation and thus entail stronger legal focus on the CACM. In addition, the TAG would also require new articles to define precisely the structure for the practical operation of a calculation and compensation mechanism, with new roles and responsibilities of stakeholders. The structure could be conceived along the following lines:

- The Nominated Electricity Market Operators (NEMOs) are responsible for matching orders from DAM and IDM for different bidding zones and simultaneously allocating

cross-zonal capacities the market coupling operating (Market Coupling Operator/MCO function). To this end, the NEMOs receive information on the transmission capacity availabilities. A market monitoring unit at the NEMO level could collect and analyze the information received on a daily basis, in order to detect situations of operational capacity reduction. In case AHC is implemented, NEMOs could calculate the compensations (volume- or price-based) based on the intra-zonal CNEs published by the TSOs.

- The identified cases of operational capacity reductions and associated compensations would be shared with the NRAs on a weekly or monthly basis. This would trigger deeper investigation by a market monitoring unit at the level of the NRA.
- In case of confirmed operational capacity reductions the NEMOs could dynamically settle the compensation with TSOs and hybrid assets as part of the daily settlement process (e.g. directly return the CI leftover to TSOs), with oversight from NRAs.

	FCA GL (2016/1719)	CACM (2015/1222)	CEP - IEM (2019/943)	CEP - ED (2019/944)	RED II (2018/2001)
<b>Option 1 :</b> <b>CI-FTR</b>	<ul style="list-style-type: none"> <li>Art3.c : non discriminatory access to LT capacity</li> <li>Art 10: capacity calculation methodology</li> <li>Art. 28: allocation principles</li> </ul>	No changes foreseen in CACM – only LT allocation is changed	<ul style="list-style-type: none"> <li>Art 9.2: market-based &amp; nondiscriminatory allocation of LTTRs</li> <li>Art 19: CI priority usage</li> </ul>	None	<i>Art16: organization and duration of the permit-granting process ?</i>
<b>Option 2 :</b> <b>CI-CfD</b>	<ul style="list-style-type: none"> <li>Art3.c : non discriminatory access to LT capacity</li> <li>Art 10: capacity calculation methodology</li> <li>Art. 28: allocation principles</li> <li>Art 31. Regional design of LTTR</li> <li>Art. 35: principles for LTTR remuneration</li> <li>Art 43 &amp; 44: return and transfer of LTTRs</li> </ul>	Art. 73: CI distribution methodology (to be updated with the CI-CfD concept)	<ul style="list-style-type: none"> <li>Art 9.2: market-based &amp; nondiscriminatory allocation of LTTRs</li> <li>Art 19: CI priority usage</li> </ul>	None	<i>Art16: organization and duration of the permit-granting process ?</i>
<b>Option 3 :</b> <b>TAG</b>	No changes foreseen in FCA – TAG does not affect capacity allocated LT	<ul style="list-style-type: none"> <li>Art 7 &amp; 8 : NEMO &amp; TSO tasks</li> <li>Art 29 regional calculation of cross-zonal capacity (esp. 29.c)</li> <li>Art. 68: clearing &amp; settlement</li> </ul>	<ul style="list-style-type: none"> <li>) Art 19: CI priority usage</li> <li>Art 49: inter-TSO compensation mechanism</li> </ul>	None	None

**Table 7: Legal assessment of studied options**

**Red:** Direct conflict

**Orange** Indirect conflict

**Green** No conflict but amendment(s) necessary



## **CONCLUSIONS AND RECOMMENDATION**

Dedicated offshore bidding zones value transmission and generation capacity more efficiently. We argue that the alternative distribution of the hybrid project's value among offshore generators and Transmission System Operators does not provide any basis for the implementation of a reallocation methodology in favor of the former. It is the natural consequence of a more efficient delineation of bidding zones.

Still, dedicated offshore bidding zones clearly induce shifts in the risk profile faced by each stakeholder when compared to an integration in existing (onshore) bidding zones. For instance, smaller bidding zones increase the need for hedging transmission risk on forward markets and liquidity is an issue if market participants are not provided with adequate tools. We concluded in an earlier report (Laur & Küpper, 2021) that this issue can be addressed by reviewing the Forward Capacity Allocation Guideline, in view of increasing liquidity in the trading of Financial Transmission Rights. In the present report, we argue that offshore bidding zones also accentuate the economic impact of the transmission capacity availability for offshore generators. In particular, the utilization of deratings for hybrid cross-zonal transmission capacity provided to the market, clearly creates a risk for offshore generators that is currently not addressed. Such deratings cannot be justified internal congestion as there is no internal congestion in offshore bidding zones by definition. Hence, if deratings are applied, it is therefore to account for the effect of congestion elsewhere in the system. These "operational deratings" exposes offshore generators located in a dedicated offshore bidding zone to specific transmission risk that may justify the implementation of measures to mitigate it.

Past studies such as (THEMA Consulting Group, 2020) or (ENTSO-E, 2021) have already discussed a number of congestion income (CI) redistribution options. Although these studies did not identify the operational deratings as a specific risk of offshore generators, the identified options could also address this issue. While some were found to require only modest integration efforts, others appeared in direct contradiction of fundamental EU principles and were found as such quite unrealistic. In this report, we studied therefore 2 of these options in more detail: CI-FTRs and CI-CfDs. Both options have in common that they are not directly targeted at the identified problem, which is the operational derating. Offshore generators can activate the option whenever the price of the reference onshore bidding zone is higher than the offshore bidding zone price. CI-FTR and CI-CfD therefore tend to overcompensate offshore generators for the specific transmission risk they face. This is why we conceptualized a third option in the course of this report: the Transmission Access Guarantee (TAG) intends instead to tackle the risk at the source, by defining a compensation paid by the TSO to offshore generators if the latter face transmission capacity reductions as a result of operational deratings. The payment of the TAG compensation would be triggered if the total export capability of the OBZ was smaller than the total net installed offshore renewable generation capacity. The compensation would correspond to

*TAG compensation = Max(Reference bidding zone price – OBZ price, 0) x total offshore generation available.*

The comparison of these 3 options leads to the following conclusions and recommendations:

### **Addressing the identified problem**



*Options 1 & 2:* The allocation of CI-FTR or CI-CfD is not directly targeted at the identified problem (operational capacity reductions) and leads to overcompensation to offshore generation. This creates issues at several levels:

- The mechanisms are difficult to scale-up, since increasing amounts of CI have to be shifted from TSOs to offshore generators if more hybrid projects are implemented, which may endanger revenue adequacy of regional TSOs. This may also provide disincentives to the TSOs to propose hybrid infrastructure projects (and to ENTSO-E in the Strategic offshore network development plans);
- Eligibility to the mechanisms might be an issue: assets located in “smaller” onshore bidding zones could be discriminated and may claim to be treated in the same way and defining eligibility criteria may therefore prove complex;
- The mechanisms represent a non-transparent way of supporting offshore renewable energy. There is no clear reason why CI should be used to support offshore renewable energy. Traditional, direct support mechanisms provide information on the support cost more transparently;
- With more hybrid projects, TSOs will have to shift increasing amounts of CI that they will have to be compensated by higher grid tariffs. The national discussion of increasing grid tariffs tends to be challenging, as so it can be having support schemes for renewables in place. With a shift that has impacts on tariffs instead of state aid, the public support is moved from taxpayers’ to consumers’ contributions and may result in a delayed investment on the necessary offshore grids. Therefore, any shifts of congestion income needs to be proportional and limited to the barriers identified in this report. Moreover, a large-scale deployment of CI-FTRs or CI-CfDs will tend to increase the relative importance of grid charges in the final electricity tariff, thus rendering demand side flexibility (where only the commodity price can be recovered) less attractive.

The mechanisms should be phased out if smaller BZs are defined or if grids are reinforced in the future. Operational deratings should occur less and less. However, the proposed contracts according to Options 1 and 2 do not phase-out by design and it might be difficult to abolish them as it shifts potentially large amounts of revenues to offshore generators. *Option 3:* TAGs, on the other hand, are directly targeted at the identified problem and minimize the issues described above.

*All Options:* None of the mechanisms guarantee hybrid projects to realize a positive business case, which was never the primary objective of this work. As mentioned by stakeholders during workshops organized in the course of this work, the proposed options might still need to be complemented with a direct support mechanism or PPAs to unlock investment.

## **Operational aspects**

*Option 1:* The amount of issued FTRs is currently restricted by the physical capacity of the interconnector. Thus, issues arise when/if the capacity of the offshore wind farm exceeds the capacity of the cable in the direction of the reference BZ. In such instances, the wind farm would not be fully hedged. Alternatives could include providing additional CI-FTRs on secondary paths (complex design) or exceeding the physical interconnector limit (revenue adequacy issues for the concerned TSO since CI may no longer cover the contract values). In such cases, joint ownership of the hybrid links across all TSOs involved in the project or other socialization mechanisms (as defined in the CI sharing methodologies for instance) can distribute the costs and help TSOs to remain revenue adequate.. Besides, the free allocation round of FTR would need to be aligned with the current auctioning process

coordinated by the Joint Allocation Office (JAO). Today, FTRs are only auctioned with delivery periods up to a year. A long-term support scheme would therefore require either regular re-allocation rounds or regulatory changes to lengthen the time coverage of such contracts. The latter may impose additional financial pressure on TSOs beyond a certain horizon due to the rising uncertainty of the network state at delivery and the obligation to remunerate the volumes sold (firmness).

*Option 2:* As opposed to CI-FTR based on a fixed volume, CI-CfD are usually designed 'as-produced', which means they do not cover against dispatch restrictions. In other words, if operational deratings force the offshore wind production below its operational maximum, only the resulting dispatched volume is covered. Also, similar to CI-FTRs, the revenue adequacy of the TSO owning the interconnector to the reference bidding zone (counterparty to the contract) might not be ensured if/at times when the wind production exceeds the flow on the cable, i.e. the CI collected. This is further reinforced by the fact that the CI-CfD would have to co-exist with the present FTR mechanism. The same CI would have to be used to remunerate two instruments, which is currently forbidden by the regulation (and difficult to manage regardless).

*Option 3:* The TAG is activated if the total export capability of the offshore bidding zone is smaller than the total net installed offshore renewable energy in that bidding zone. This rule is suitable for all network representations (NTC, Flow-Based, Flow-Based with Advanced Hybrid Coupling). Furthermore, there is no interference with existing LTTR mechanisms.

## **Implementation of the options**

*Options 1 & 2:* CI-FTR and CI-CfD mostly necessitate amendments of the Forward Capacity Allocation (FCA) Regulation, which oversees the forward allocation process. First, the objectives defined in article 3 would have to be adapted for both the CI-FTR and the CI-CfD, as this regulation aims, among others, at "providing non-discriminatory access to long-term cross-zonal capacity". Second, both the CI-FTR and the CI-CfD would require a change to article 28 defining the general principles of forward capacity allocation. Furthermore, the CI-CfD would require amendments to several articles related to product design (articles 31, 35, 43 and 44), as it is not considered today as a Long-Term Transmission Right. Beyond the FCA Regulation, the CI-CfD would necessitate an amendment to article 73 of the CACM defining the requirements for the methodology for sharing congestion income. Finally, it must be emphasized that both the CI-FTR and the CI-CfD conflict with article 9.2 of the Electricity Regulation 2019/943 stating that "long-term transmission rights shall be allocated in a transparent, market based and non-discriminatory manner through a single allocation platform".

*Option 3:* Conversely, the TAG relates to operational capacity calculation and thus entail stronger legal focus on the Capacity Allocation and Congestion management (CACM) regulation. In addition, the TAG would also require new articles to define precisely the structure for the practical operation of a calculation and compensation mechanism, with new roles and responsibilities of stakeholders (NEMOs and NRAs in particular). Finally, the TAG would also require a change to article 9.2 of the Electricity Regulation.

**Summing up,** the main barrier to creating a level-playing field between hybrid and onshore assets is the asymmetrical impact of operational capacity deratings. In this regards, various support options were analyzed and the TAG comes out as the preferred mechanism: it is focused on the issue identified, it does not create overcompensations and related issues, it is realistic and scalable from an operational standpoint. . Generally speaking, no option fully guarantees that support schemes will not be needed to secure investment. All mechanisms involve different degrees of legislative changes, but the TAG

implementation is expected to be less challenging than alternative options. It is also compatible with all network representations (NTC, FB, FB + AHC). In this regard, AHC could also help addressing the issue in Flow-Based regions where it is implemented (planned in 2023 for the Nordic CCR). Under the current design, it should in particular allow the full capacity of DC links to be allocated to the market, thereby reducing the activation frequency of the TAG. While this TSO project should in theory be faster to implement than any redistribution option, the extent to which it will resolve the identified problem in practice is not clear yet, and the TAG should remain relevant as a safeguard.

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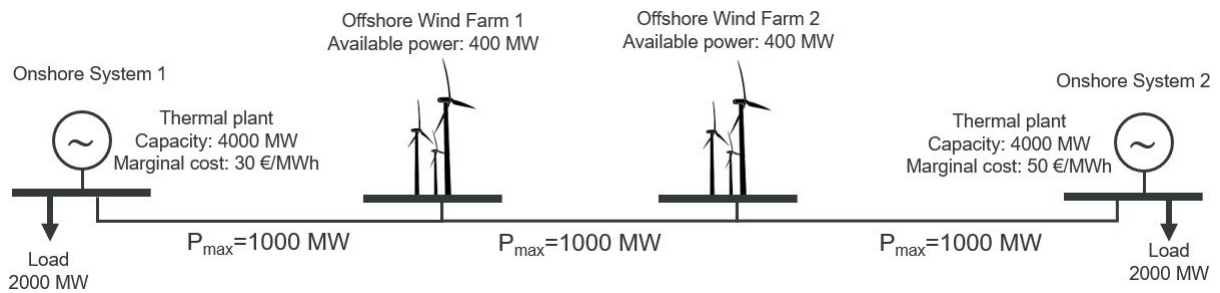
## APPENDICES

### A- Optimal dispatch and price-setting in offshore bidding zones

The purpose of this first appendix is to show that, when offshore bidding zones always meet the idealistic assumptions behind zonal markets (i.e. each bidding zone is supposed to be internally a copper plate), the distribution of the socio-economic welfare between stakeholders is independent on the bidding zone configurations. On the contrary, when offshore bidding zones do not always meet these idealistic assumptions, the distribution of the socio-economic welfare between stakeholders is dependent on the bidding zone configurations, but the market can become less efficient. For that purpose, we will analyze two different cases with two onshore systems connected by an hybrid asset gathering two offshore wind farms. In the first case, the transmission capacity between the two offshore wind farms will be such that no congestion can appear between the two offshore wind farms, while it will be the opposite in the second case. For the two cases, two bidding zone configurations will be analyzed: two small offshore bidding zones consisting of only one wind farm, and one large offshore bidding zone gathering the two offshore wind farms.

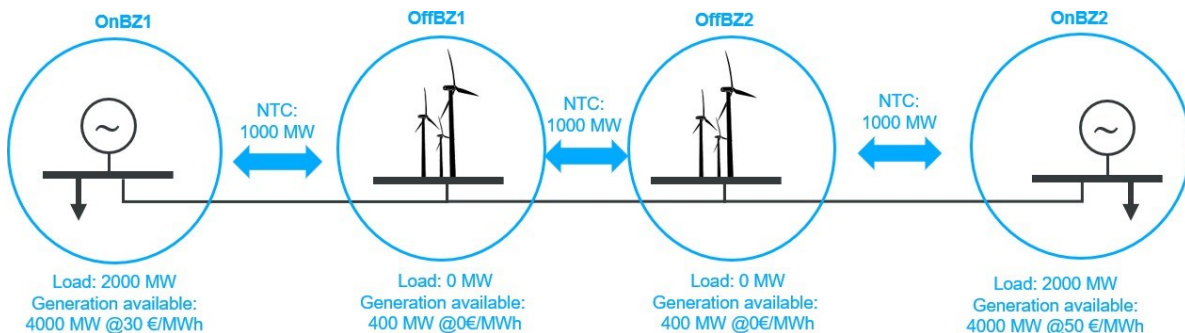
#### Case 1

Consider the case shown in the following figure. We have two onshore systems connected by an hybrid asset gathering two offshore wind farms. The transmission capacity between the two offshore wind farms and between each offshore wind farm and the shore is 1000 MW. Each onshore system has an electrical load of 2000 MW. In the first onshore system, a thermal plant of 4000 MW with a marginal cost of 30 €/MWh is available. In the second onshore system, a thermal plant of 4000 MW with a marginal cost of 50 €/MWh is available. Assume that the available power from each wind farm is 400 MW (for a capacity of 1000 MW).



**Figure 8: Case 1**

The first market design analyzed consists in creating a dedicated offshore bidding zone for each offshore wind farm. The following figure shows the market configuration.



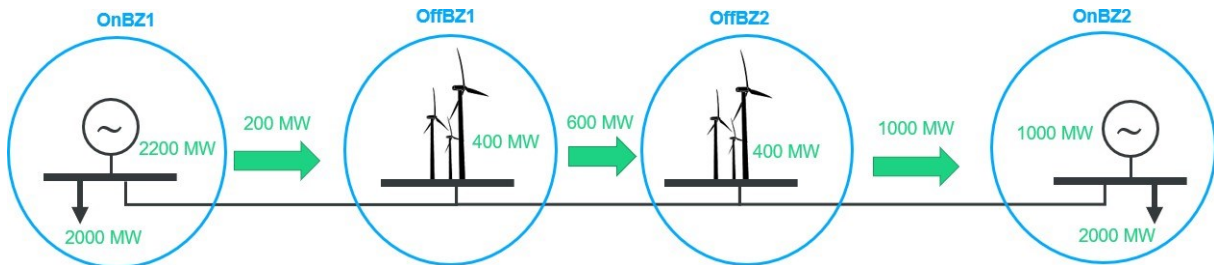


**Figure 9: Case 1 – Two offshore bidding zones**

In order to compute the market outcome, we can use the following steps:

- The generation is the most expensive in OnBZ2. That zone must thus import as much as it can, i.e. 1000 MW. The other 1000 MW necessary to supply the local load will come from the local generation.
- OffBZ2 will have thus to provide 1000 MW to OnBZ2. There is no load in OffBZ2 and the available generation is 400 MW. As the available generation is the cheapest in the system, all that generation will be used and sent to OnBZ2. The difference between the 1000 MW transferred from OffBZ2 to OnBZ2 and the contribution of 400 MW of OffBZ2, i.e. 600 MW, will have to come from OffBZ1.
- OffBZ1 will have thus to provide 600 MW to OffBZ2. There is no load in OffBZ1 and the available generation is 400 MW. As the available generation is the cheapest in the system, all that generation will be used and sent to OffBZ2. The difference between the 600 MW transferred from OffBZ1 to OffBZ2 and the contribution of 400 MW of OffBZ1, i.e. 200 MW, will have to come from OnBZ1.
- The generator of OnBZ1 will have thus to provide 200 MW to OffBZ1, but also 2000 MW to the local load. It will thus generate 2200 MW.

The resulting dispatch is shown in the following figure.

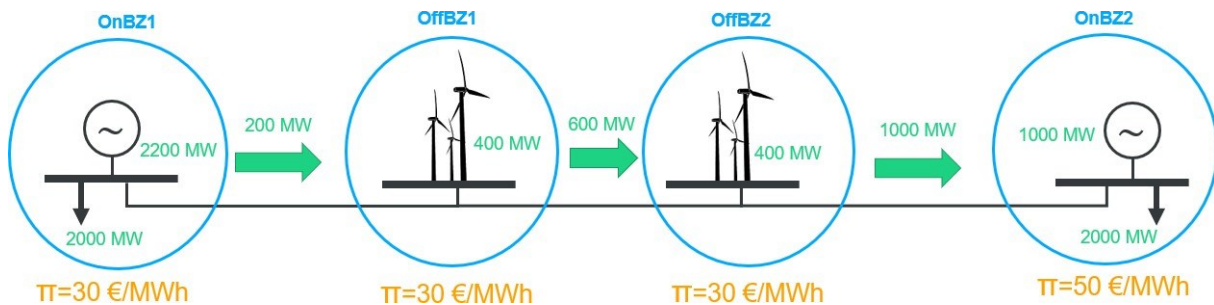


**Figure 10: Case 1 – Two offshore bidding zones – Market dispatch**

Based on this dispatch, we can compute the electricity prices in each zone, as the marginal cost required to supply an additional MWh of load:

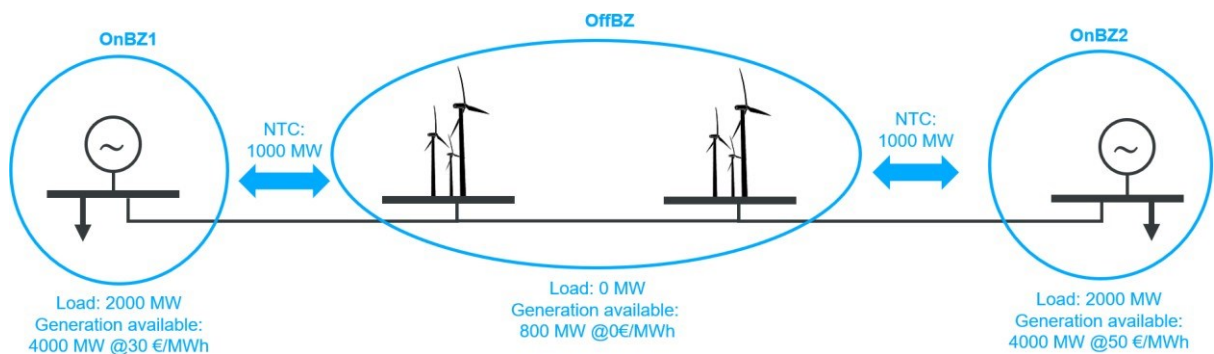
- In OnBZ1, if the load increases by 1 MW, the cheapest way to supply it is to increase the local generation by 1 MW. Indeed, it is not possible to supply it from the offshore wind farms, as they are already generating all they can, and it would be more expensive to increase the generation in OnBZ2 by 1 MW. As the marginal cost of the local generation is 30 €/MWh, the electricity price is 30 €/MWh.
- In OffBZ1 and in OffBZ2, if the load increases by 1 MW, the cheapest way to supply it is to increase the generation in OnBZ1 by 1 MW. Indeed, it is not possible to supply it from the offshore wind farms, as they are already generating all they can, and it would be more expensive to increase the generation in OnBZ2 by 1 MW. As the marginal cost of the generation in OnBZ1 is 30 €/MWh, the electricity price in OffBZ1 and in OffBZ2 is 30 €/MWh.
- In OnBZ2, if the load increases by 1 MW, the cheapest way to supply it is to increase the local generation by 1 MW. Indeed, as the interconnection between OffBZ2 and OnBZ2 is congested, it is not possible to import an additional MW. As the marginal cost of the local generation is 50 €/MWh, the electricity price is 50 €/MWh.

The full market outcome, including the zonal electricity prices, is given in the following figure.



**Figure 11: Case 1 – Two offshore bidding zones – Full market outcome**

The second market design analyzed consists in creating a single offshore bidding zone for the two offshore wind farms. The following figure shows the market configuration.

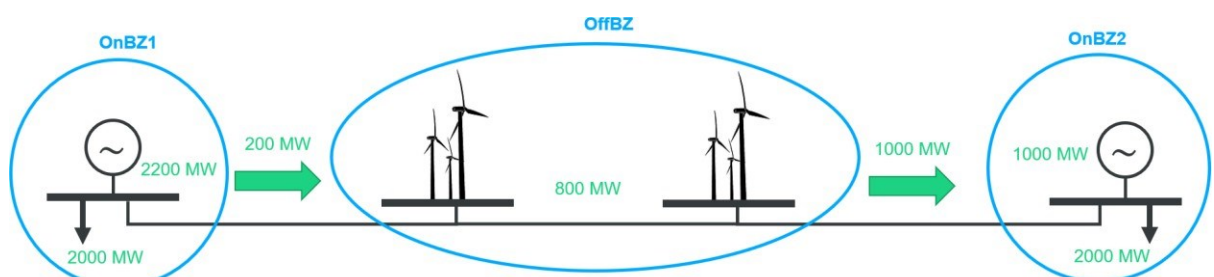


**Figure 12: Case 1 – Single offshore bidding zone**

In order to compute the market outcome, we can use the following steps:

- The generation is the most expensive in OnBZ2. That zone must thus import as much as it can, i.e. 1000 MW. The other 1000 MW necessary to supply the local load will come from the local generation.
- OffBZ will have thus to provide 1000 MW to OnBZ2. There is no load in OffBZ and the available generation is 800 MW. As the available generation is the cheapest in the system, all that generation will be used and sent to OnBZ2. The difference between the 1000 MW transferred from OffBZ to OnBZ2 and the contribution of 800 MW of OffBZ, i.e. 200 MW, will have to come from OnBZ1.
- The generator of OnBZ1 will have thus to provide 200 MW to OffBZ1, but also 2000 MW to the local load. It will thus generate 2200 MW.

The resulting dispatch is shown in the following figure. Note that a power flow analysis indicates a flow of 600 MW on the internal transmission line of OffBZ, compatible with the rating of 1000 MW. There is thus no need of redispatch.





### Figure 13: Case 1 – Single offshore bidding zone – Market dispatch

Based on this dispatch, we can compute the electricity prices in each zone, as the marginal cost required to supply an additional MWh of load:

- In OnBZ1, if the load increases by 1 MW, the cheapest way to supply it is to increase the local generation by 1 MW. Indeed, it is not possible to supply it from the offshore wind farms, as they are already generating all they can, and it would be more expensive to increase the generation in OnBZ2 by 1 MW. As the marginal cost of the local generation is 30 €/MWh, the electricity price is 30 €/MWh.
- In OffBZ, if the load increases by 1 MW, the cheapest way to supply it is to increase the generation in OnBZ1 by 1 MW. Indeed, it is not possible to supply it from the offshore wind farms, as they are already generating all they can, and it would be more expensive to increase the generation in OnBZ2 by 1 MW. As the marginal cost of the generation in OnBZ1 is 30 €/MWh, the electricity price in OffBZ is 30 €/MWh.
- In OnBZ2, if the load increases by 1 MW, the cheapest way to supply it is to increase the local generation by 1 MW. Indeed, as the interconnection between OffBZ and OnBZ2 is congested, it is not possible to import an additional MW. As the marginal cost of the local generation is 50 €/MWh, the electricity price is 50 €/MWh.

The full market outcome, including the zonal electricity prices, is given in the following figure. It must be emphasized that this outcome is exactly the same as the one obtained with two offshore bidding zones, as the single offshore bidding zone meets perfectly the idealistic assumptions of zonal markets.

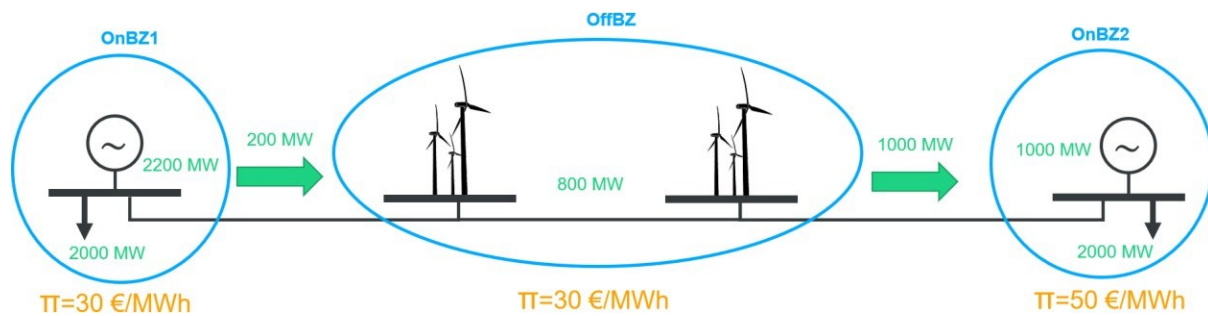


Figure 14: Case 1 – Single offshore bidding zone – Full market outcome

### Case 2

The second case analyzed is similar to the first one, except that the transmission capacity between the two offshore wind farms is now only 500 MW (instead of 1000 MW in case 1).

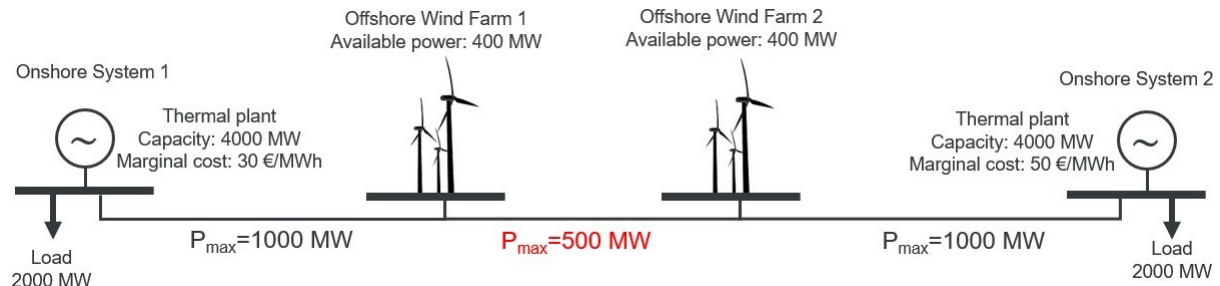
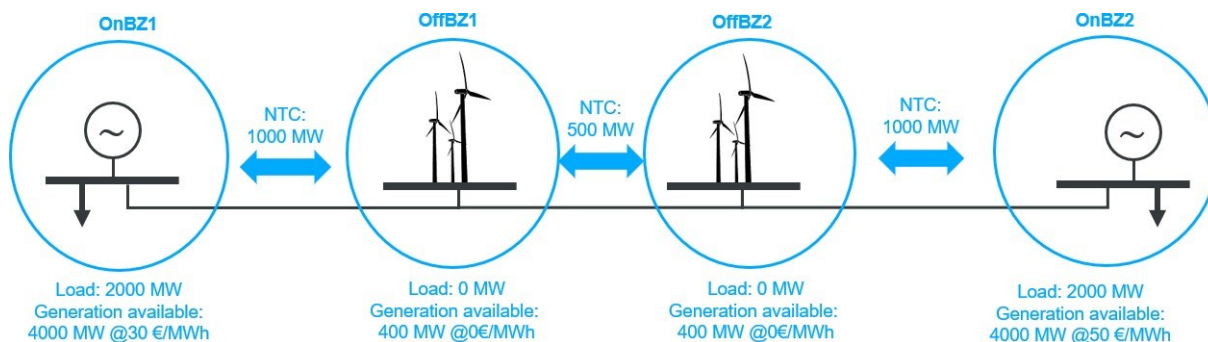


Figure 15: Case 2

The first market design analyzed consists again in creating a dedicated offshore bidding zone for each offshore wind farm. The following figure shows the market configuration.

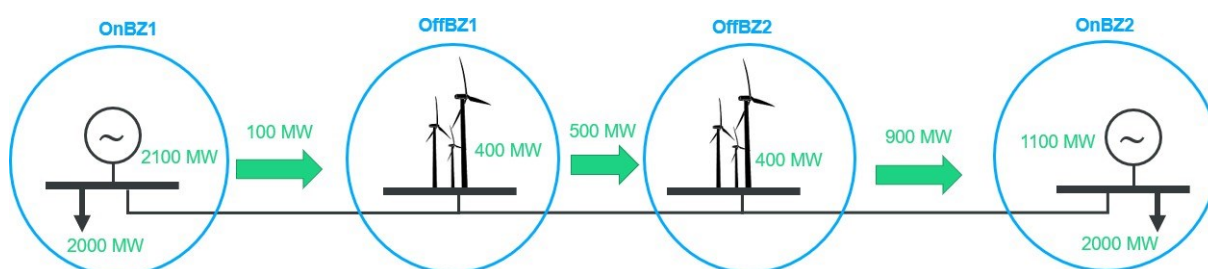


**Figure 16: Case 2 – Two offshore bidding zones**

The computation of the market outcome is now a little bit more complicated, but we can use nevertheless the following steps:

- The generation is the most expensive in OnBZ2. That zone should thus import as much as it can. Let's assume first OnBZ2 can import 1000 MW from OffBZ2. There is no load in OffBZ2 and the available generation is 400 MW. To be able to export 1000 MW to OnBZ2, OffBZ2 should thus import 600 MW from OffBZ1, which is not possible because the NTC between OffBZ1 and OffBZ2 is only 500 MW. OffBZ2 will thus be able to export only 900 MW (i.e. 400 MW coming from local generation and 500 MW coming from OffBZ1) to OnBZ2. The other 1100 MW necessary to supply the local load of OnBZ2 will come from the local generation.
- OffBZ1 will have thus to provide 500 MW to OffBZ2. There is no load in OffBZ1 and the available generation is 400 MW. As the available generation is the cheapest in the system, all that generation will be used and sent to OffBZ2. The difference between the 500 MW transferred from OffBZ1 to OffBZ2 and the contribution of 400 MW of OffBZ1, i.e. 100 MW, will have to come from OnBZ1.
- The generator of OnBZ1 will have thus to provide 100 MW to OffBZ1, but also 2000 MW to the local load. It will thus generate 2100 MW.

The resulting dispatch is shown in the following figure.



**Figure 17: Case 2 – Two offshore bidding zones – Market dispatch**

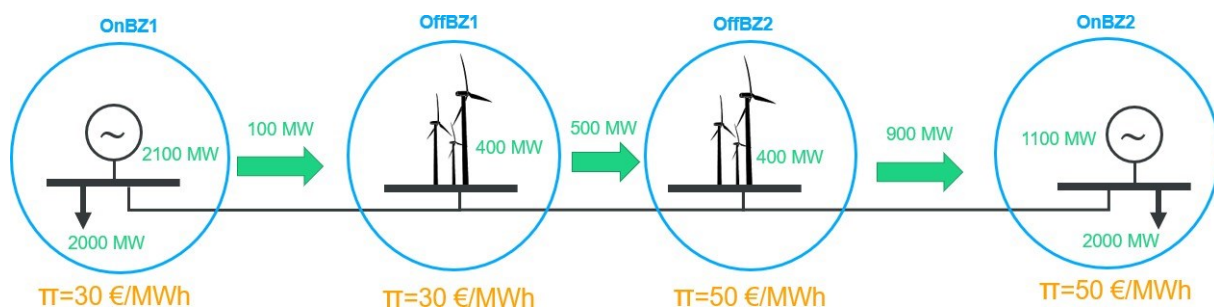
Based on this dispatch, we can compute the electricity prices in each zone, as the marginal cost required to supply an additional MWh of load:

- In OnBZ1, if the load increases by 1 MW, the cheapest way to supply it is to increase the local generation by 1 MW. Indeed, it is not possible to supply it from the offshore wind farms, as they are already generating all they can, and it would be more expensive to increase the generation in OnBZ2 by 1 MW. As the marginal cost of the local generation is 30 €/MWh, the electricity price is 30 €/MWh.
- In OffBZ1, if the load increases by 1 MW, the cheapest way to supply it is to increase the generation in OnBZ1 by 1 MW. Indeed, it is not possible to supply it from the offshore wind farms, as they are already generating all they can, and it would be

more expensive to increase the generation in OnBZ2 by 1 MW. As the marginal cost of the generation in OnBZ1 is 30 €/MWh, the electricity price in OffBZ1 is 30 €/MWh.

- In OffBZ2, if the load increases by 1 MW, the cheapest way to supply it is to increase the generation in OnBZ2 by 1 MW. Indeed, it is not possible to supply it from the offshore wind farms, as they are already generating all they can, and it is not possible either to supply it from OnBZ1 as the transmission line between OffBZ1 and OffBZ2 is congested. As the marginal cost of the generation in OnBZ2 is 50 €/MWh, the electricity price in OffBZ2 is 50 €/MWh.
- In OnBZ2, if the load increases by 1 MW, the cheapest way to supply it is to increase the local generation by 1 MW. Indeed, as the interconnection between OffBZ1 and OffBZ2 is congested, it is not possible to import an additional MW from OnBZ1. As the marginal cost of the local generation is 50 €/MWh, the electricity price is 50 €/MWh.

The full market outcome, including the zonal electricity prices, is given in the following figure.



**Figure 18: Case 2 – Two offshore bidding zones – Full market outcome**

The second market design analyzed consists in creating a single offshore bidding zone for the two offshore wind farms. The market configuration is then the same as the one of the first case, illustrated in **Error! Reference source not found..** The full market outcome, including the zonal electricity prices, is thus also given in **Error! Reference source not found..** However, it must be emphasized that, in this case, a power flow analysis indicates a flow of 600 MW on the internal transmission line of OffBZ, incompatible with the rating of 500 MW. There is thus a need of redispatch (countertrading in this case). Furthermore, the market outcomes (dispatches, flows and prices) are different for the two different bidding zone configurations, as illustrated by the comparison of **Error! Reference source not found.** and of **Error! Reference source not found..** The distribution of the socio-economic welfare depends thus on the bidding zone configuration, but it is because the single bidding zone configuration does not meet the idealistic assumption of zonal markets: the offshore bidding zone is not a copper plate, as there is an internal congestion.

## **B- Detailed description of CI redistribution options:**

### **Congestion Income Contract for Differences (CI-CfD)**

A Contract for Differences (CfD) is a well-known contracts in energy finance, by means of which the market price received for production is swapped against a strike price over a predefined period of time, typically 10-20 years. It therefore corresponds to a two-sided financial obligation with the counterparty who is often a utility or a governmental body: when the market price is below the strike, the generator receives a payment, but it must pay back the surplus in the opposite case. This type of contract is already being used in the European electricity market to incentivise the build-up of renewable electricity generation, although they do not usually involve directly regulated entities such as TSOs.

With “traditional” CfDs, the strike is typically fixed (determined through competitive tenders) so that the generator is fully hedged against market price risk. In the case of offshore BZs, the CfD’s objective is not to remove any price risk, but rather to transfer congestion income back to the offshore generator and create a level-playing field for the OWF. Consequently, the CI-CfD is better designed under a variable strike price, which may correspond to the market price of an onshore Bidding Zone. In this case, the counterparty is naturally the entity that locally collects congestion income (TSO or private transmission owner).

In effect, this means that for the offshore production is always remunerated at the chosen onshore market price (strike). If the intention is to create a level-playing field, and especially with respect to assets under the same regime but located in an Onshore Bidding Zone, then the most sensible choice is to use the Home Market price as strike. The hourly (h) value for this CI-CfD can therefore be summarized as:

$$Value_h = Scheduled\ Production_{OWF,h} * (DA\ Price_{HM,h} - DA\ Price_{OBZ,h})$$

The generator participates in the wholesale market by bidding in its own BZ. After the market clearing, it receives the Day-Ahead price of its BZ for the scheduled volume. The TSO, who captures the price spread via the congestion income, then commits to pay back the positive difference between the reference BZ and OBZ price for the scheduled volume. On the contrary, if the price spread is negative, the offshore generator must pay the TSO back for the excess received. We illustrate the CI-CfD below:

<b>CI-CfD: Quantitative illustration</b>					
Based on the configuration shown in the introduction to section 3, we assume a CI-CfD is signed for the total offshore generation park, between OBZ1 and DKW1 (its reference BZ). The contract is as-produced and based on the results of the DAM (its value therefore corresponds to the above formula). The contract performs as follows:					
		2030	2030	2040	2040
		Without outage	With outage	Without outage	With outage
<b>CfD Value</b>	M€	4.09	60.67	15.20	91.96
<b>Revenue top-up from CfD</b>	%	1.25%	7.17%	3.37%	7.85%
<b>CI OBZ-DK captured</b>	%	96.60%	265.09%	73.13%	204.12%
<b>Tot CI captured</b>	%	36.88%	90.31%	45.46%	84.58%

The simulation shows that the revenue top-up for the OWF is moderate under normal conditions (1-3%), but increases substantially to 7-8% in the scenario with outages. In the latter case, payments made by the TSO(s) can exceed the value of the congestion income collected on the OBZ-DK (reference) border – but not that of the total hybrid system. This is because the reduced transmission capacity on that link forces the system to also evacuate some power towards Belgium in order to avoid curtailment (the OWF exports in both directions). In this case, the asset production becomes larger than the flow towards the HM and given equal price spreads, the CI-CfD value is higher.

One of the main advantages of the CI-CfD is its financial “point-to-point” characteristic: the contract is completely network-agnostic in the sense that it is not impacted by physical topology changes (network augmentations, meshed grids,...). In theory, there does not even need to be a direct link to the reference Bidding Zone for the strike price to be established as such. It should be noted however that, even with a resilient contract structure, network congestion or unavailability can impact the CI-CfD if they lead to curtailment of the asset production. The contract duration is also very flexible and can extend to cover the entire asset lifetime, which facilitates. The hedging value of the contract also be impacted by economic topology changes: for instance if the zone linked to the strike price were to undergo a Bidding Zone review. One alternative could then be

to use a weighted price index or a dynamic strike (zonal reassignment based on market conditions), although there may be risks or overcompensation and over-complexification. Indeed, to fulfil its role in attracting investment, the contract also should remain simple enough not to create additional barriers.

The main issues with the CI-CfD relates to the alignment with the European legal framework. Currently and as discussed in section 1, the congestion income collected by regulated TSO must first and foremost be used for grid enhancements, system security and tariff setting. Thus, any bespoke redistribution methodology becomes de facto incompatible with this principle. Further, the CI redistribution by CI-CfD may pose a revenue adequacy problem for TSOs when considering the already-existing redistribution through the LTTR mechanism. Legal arrangements would have to be found between these two schemes.

### **Congestion Income Financial Transmission Rights (CI-FTRs)**

Financial Transmission rights (FTRs) are forward energy derivative contracts which hedge against locational price volatility in the Day-Ahead market. In the EU, FTRs are currently implemented as Options. These products thus entitle their holder to an optional payment equal to the price spread between two adjacent Bidding Zones (BZs) multiplied by the purchased volume. The option is only exercised if the chosen flow direction leads to a positive pay-out (positive spread). FTRs, alongside Physical Transmission Rights (PTRs), represent the two forms of LTTRs currently in force in the EU.

As described in Section 1, “standard” FTRs redistribute the realized congestion income captured by the TSO to market participants. An offshore asset could therefore sell its production on a neighbouring mainland market and obtain a price hedge against that Bidding Zone (in case of a positive spread) by purchasing an equivalent quantity of FTRs over the interconnector. FTRs are explicitly distributed (auctioned) to participants over yearly and monthly timeframes via the Joint Allocation Office (JAO) platform. The volumes offered are defined by the respective TSOs on each interconnector separately. Moreover, TSOs may decide to auction only a portion of the interconnector capacity for FTRs (e.g. for security of supply or revenue adequacy reasons), which imply that only part of the total production may recover the congestion income if the latter exceeds the volume offered.



The CI-FTR could therefore naturally be aligned on the current FTR design. If there is a direct physical link between the OBZ and its reference BZ, the hourly value captured by the offshore generator would correspond to the following:

$$Value_h = Volume\ purchased_{OBZ \rightarrow HM,h} * Max(DA\ Price_{HM,h} - DA\ Price_{OBZ,h}, 0)$$

#### **CI-FTR: Quantitative illustration**

Based on the configuration shown in the introduction to section 3, we assume a CI-FTR is signed for the total capacity of the interconnector connecting to the reference BZ (1,4GW), in the direction OBZ1→DKW1. In this case, the entire production may not always be covered as the generation capacity totals 2.8GW. The contract performs as follows:

		2030	2030	2040	2040
		Without outage	With outage	Without outage	With outage
<b>FTR Value</b>	M€	4.23	42.22	20.78	72.77
<b>Revenue top-up from FTR</b>	%	0.46%	4.99%	1.65%	6.21%
<b>CI OBZ-DK captured</b>	%	100.00%	184.47%	100.00%	161.53%
<b>Tot CI captured</b>	%	38.18%	62.84%	62.16%	66.94%

The simulation shows that the revenue top-up for the offshore generator also increases with outages, up to 5-6% but remains below the value accrued from the CI-CfD. This is because in this case, the interconnector capacity is lower than the offshore generator's nominal capacity (2.8GW) and therefore the entire production is not always covered by the contract.

When the OBZ-DK interconnector is at 100% availability, then the CI-FTR value exactly equal the CI collected. Indeed, when price decoupling occur, the interconnector is congested (eg flow = volume purchased = interconnector capacity), and the price spread is always positive (the OBZ price is always lower than the onshore one in an NTC radial configuration). Thus, the two expressions become identical. However, when the interconnector availability drops, the maximum admittable flow also decrease while the purchased FTR volume remains unchanged. In that case, given equal price spread, the value of the FTR therefore exceeds the OBZ-DK CI and the TSO must remunerate the contracted capacity (firmness). In any case, FTR payments never exceed the total CI captured across the hybrid system.

One important feature of FTRs is that the capacity firmness is always ensured by TSOs, and full compensation is expected even in case of operational transmission deratings that would curtail the offshore production. Secondly, as opposed to PTRs, they do not restrict the transmission capacity released for the DAM. The volumes sold are purely financial and used post market-clearing for settlement purposes: even if the full link capacity is sold forward, that same capacity still remains available for use at the Day-Ahead stage. This is especially important in the context of the recently adopted 70% rule<sup>18</sup>, and a crucial aspect for hybrid systems where transmission availability is the central issue. Last but not least, FTRs can be sold back on secondary markets after initial allocation, which gives flexibility to their holder to recover or redeploy some capital if necessary.

On the other hand, FTRs – in their current design – are products defined on specific interconnectors, which means that without the presence of a direct link to the reference BZ, a portfolio of multiple contract would be necessary to establish the onshore hedge. Another drawback lies in the delivery period, which is currently capped to a year. Hence,

<sup>18</sup> Following Article 16.8 of EU regulation 2019/943, TSOs must henceforth offer at least 70% of transmission capacity for cross-zonal interconnectors to the DAM, excluding reliability margins and other security discounts.

FTRs cannot provide a protection against congestion over the full investment period of an offshore project, which makes them much shorter-term solutions than CfDs lasting decades. FTR buyers must partake in periodic allocation rounds (which are each subject to a price/volume risk linked to the outcome of the auction) to retain their hedge.

Altogether, the bespoke CI-FTR solution could simply consist in 1) incentivizing offshore generators to compete for forwards transmission capacity in regular FTR auctions, against other market participants and 2) ensuring that the FTR market is as efficient and forward-looking as possible. Such a solution would mitigate the locational risk (volatility) issue but would not fully address the revenue level component since the CI-FTRs has to be purchased by the OWF at an uncertain price. In addition, if congestion in hybrid system is structural and easily forecasted, the FTR market may attract buying pressure from other participants or traders having identified profit opportunities. This extra demand could in turn raise the auction clearing price and reduce the net value captured by OWFs from this mechanism.

A more comprehensive form of support could alternatively be found by providing offshore project developers with free or pre-allocated CI-FTRs. The CI-FTRs reserved that way are taken out of the market, and only the remaining volume is auctioned. From a regulatory perspective however, this would tend towards a direct support mechanism rather than a pure market-based arrangement. Discriminatory allocation of FTRs on JAO is also currently in direct violation of Article 9 of EU Regulation 2019/943.

More generally, the FTR design is not unique and may be subject to changes as part of an FCA-GL review. (Laur & Küpper, 2021) described why the current implementation may not cope well with the increasing renewable penetration and provided alternatives to recast some of the incumbent arrangements. The considered options included a potential shift from the current “flowgate” Option FTR (tied to a specific interconnector) to an Obligation Zone-to-Hub FTR. With Zone-to-Hub, the generator no longer hedges against the onshore zonal price, but against a synthetic price resulting for instance from an average of several neighbouring BZs. The Obligation makes the FTR a perfect (bi-directional) hedge against the Hub price, thereby requiring repayments in case of a negative spread. Zone-to-Hub should reduce transaction premiums by encouraging better liquidity, and also simplify the hedging process of the offshore asset (no need to build a portfolio of contracts when no direct link is available). The remuneration from Zone-to-Hub would however differ from the realized congestion rent the asset is exposed to, in proportions determined by the chosen definition of the Hub price.

### **Congestion Income Auction Revenue Rights (CI-ARRs)**

The Auction Revenue Right (ARR) is a concept predominantly imported from US markets (e.g. PJM, MISO, SouthWest,...). In these regional power systems, ARR are typically used in conjunction with FTRs to redistribute congestion income back to Load-Serving Entities (LSE) who already paid for transmission through network tariffs.

Concretely, ARR represent a financial entitlement to a share of the revenues generated by an FTR auction, which are re-distributed by the System Operator. ARR holders can then either keep their share of the revenue as an extra compensation via a lump sum payment or convert it into an equivalent amount of FTRs (“self-scheduling”). It is worth noting that in most US systems, both ARR and FTRs are defined as Obligations. In other words, they may both result in liabilities to holders if the spread is negative.

The ARR allocation process can vary across ISOs, but typically occurs before the annual FTR auction. In PJM for instance, the ARR credits are first claimed by LSEs across source-sink pairs, either with proofs of a “Firm Point-to-Point Transmission Service” (presence of an ongoing delivery contract) or based on historical usage of the transmission capacity on that path. The requested volume of ARR cannot exceed the volume of energy served and is subject to a Simultaneous Feasibility Test. Once the available volume across all paths

has been allocated in full by the ISO, ARR holders can optionally decide to self-schedule FTRs, i.e to transform their allocation into an equivalent amount of FTRs over the same path. At the time of decision, the exact value of the ARR is not yet known since the latter depends on the results of the FTR auction, which solves a network-wide nodal optimal dispatch:

$$ARR \text{ Payout} = Volume \text{ allocated}_{ARR \text{ source} \rightarrow \text{sink}} * (FTR \text{ Price}_{\text{sink node}} - FTR \text{ Price}_{\text{source node}})$$

Where the FTR price corresponds to the clearing price of the FTR auction paid by participants at the specified location. To sum up, LSEs are granted a free allocation on the network path they physically use which can provide unknown payment, and which they must decide to trade – or not – against an FTR with equally unknown value at delivery. This choice of mechanism and timing provides flexibility while avoiding excessive gaming between the two instruments. If other network paths have to be hedged by LSEs, the associated FTRs must be purchased directly through the auction (possibly using the non-scheduled ARR payment).

In the EU, ARRs could also represent another potential option for TSOs to redistribute part of the congestion income. An adaption of the concept would however face significant challenges given that European arrangements widely differ from the above description. First, and as described in the previous subsection, the European FTR mechanism is based on disjoint, link-specific auctions of Option FTRs. This significantly changes the product properties and dynamics. In particular, FTR clearing prices are no longer defined at nodal level but for each cross-zonal interconnector. What's more, the price is no longer formed from a system-wide equilibrium, but only from local supply and demand. There is therefore no possibility for prices to converge and ARRs in low-demand locations may end up providing only very little financial support. Besides, in its original form, the ARR rationalizes the transfer of revenues back to LSEs (physical network users) based on the fact that they are the ones sharing the cost of building/maintaining transmission through their rates. On the other hand, a European "CI-ARR" would redistribute revenues to generators which are generally not - or only partially- exposed to transmission charges (ACER, 2019). Additional justification for the creation from scratch of a new instrument, designed specifically for hybrid OWFs, would presumably have to be provided.

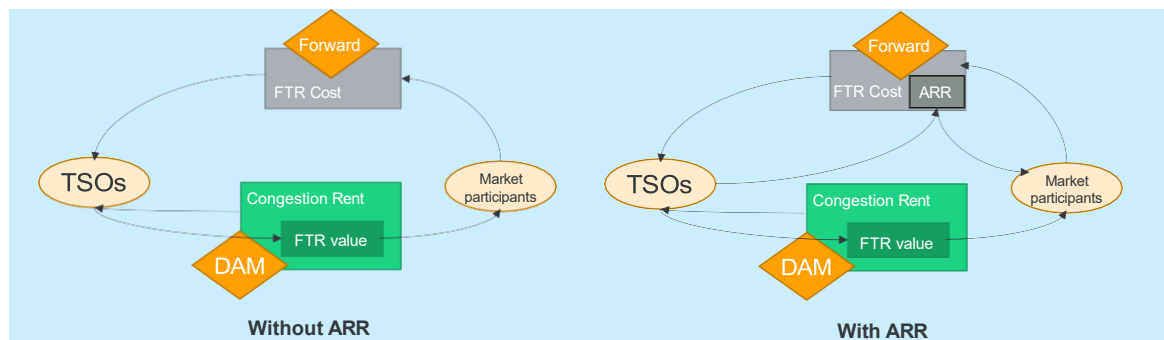
Nonetheless, CI-ARRs would act as an extra income on top of the offshore market revenues. With this instrument, payments would be received regardless of the realized congestion income (both price and volume risk remain at delivery). This could result in either over- or under-compensation for OWFs depending on market conditions. Further, since ARRs are intrinsically linked to FTRs, they would suffer from the same limited delivery horizon and need for yearly reallocation. Finally, it would be ill-advised to perform the allocation based on historical usage due to the newness of hybrid systems. Various



allocations rather based on ongoing usage could be envisioned : volume-based, peak-usage, hybrid solutions, etc..

### **CI-ARR: Quantitative illustration**

The value of CI-ARR depends on the FTR auction clearing price which cannot be reasonably simulated via a fundamental view of the power system. Thus, we do not rely on the quantitative model, but propose rather a simple theoretical example below.



Suppose the network topology used in the quantitative model still holds. The TSO puts the entire capacity of the OBZ1→DK interconnector (1.4GW) for sale in the yearly FTR auction.

Now let us suppose that the auction clears at a price of 10€/MWh. The total FTR cost to participants (proceeds of the auction received by the TSO) thus amounts to 14k€/h, or 122.3M€ over the entire year.

Taking our 2030, no outage scenario as an example, we compute the average utilization rate of the OBZ1→DK direction by the offshore generator, which equals 64.9%. If the CI-ARR is allocated based on this sharing rule, then the OWF in OBZ1 receives  $0.649 \times 1400 = 909$  ARRs with an associated total payment of  $0.649 \times 122.3 = 79.37$  M€ in forward rounds. The TSO keeps the leftover proceeds from the auction.

At delivery, let us assume a first situation where the baseload DAM prices for the target year equal 55 and 70€/MWh for the BZs OBZ1 & DK respectively. In this case, the total FTR value is  $(70-55) \times 1400 = 21$  k€/h, or 183.5M€ yearly, which is higher than the total FTR cost (to be expected since traders typically require a positive margin buying into FTRs). If the OWF converts its 909 ARRs into FTRs, it would earn 119,1M€ and m. However, in a second situation where prices for OBZ1 & DK are respectively 65 and 70€/MWh, the ARR value remains 79.37M€ while the value of converted FTRs would only amount to 39.7M€.

### **Direct allocation of congestion rent income**

Another proposed option is the direct (re)allocation of the generated congestion rent to offshore generators. Under this mechanism, the offshore generator is transferred the share of congestion rent collected in the hybrid system that directly results from its energy production.

While the idea is rather simple, the subsequent implementation presents a two-fold challenge. First, a new regulatory framework would need to be established, to define a new class of cross-zonal flows whose CI does not belong to TSOs but rather to hybrid offshore generators. The identification and eligibility of such systems as well as the sharing arrangements would need to be thoroughly defined. In a similar fashion as CI-ARRs, building new legal structures from the ground up may increase the cost, delay and eventually effectiveness of the chosen solution.

The second difficulty lies in the complexity of establishing general rules to allocate the congestion rent among offshore generators (i.e. determining the pertinent amount for each one). Such rules may become more difficult to determine when several offshore generators and TSOs are involved or when the offshore grid topology moves from radial to meshed. Nonetheless, an approach similar to the existing CI redistribution methodology covered in section 1 could be used. Overall energy exchanges can be broken down into bilateral flows across specific borders and the contribution of various parties to these flows can be

estimated. The positive contribution of each offshore generator on the load of each interconnector in the hybrid system can thus in theory be computed.

In a hypothetical situation where the entire congestion income occurs on the interconnector to the reference BZ, the direct allocation has the same value as the CI-CfD. However this is only true if the entire asset production flows in this direction (production fully exported to HM). Conversely, when the export to the reference BZ does not account for the total production, the allocation method provides less financial support than the CI-CfD. To account for this difference, the allocation could encompass not only the marginal CI towards the HM, but also on all export directions in the hybrid system. In other words, while the CI-CfD, CI-FTR and CI-ARR aim at capturing the most CI on a single link (to the reference BZ), the Direct Allocation would collect smaller contributions across all links. In an NTC representation, the value allocated could therefore be expressed as:

$$Allocation_h = \sum_{bz=0}^{Connected\ BZ} export_{OBZ \rightarrow bz,h} * (DA\ price_{bz,h} - DA\ price_{OBZ,h})$$

This formulation has the advantage to remunerate the OWF only on its marginal contribution to the system CI, and thereby does not compensate for CI generated by other resources. Meanwhile, in the CI-FTR for instance, the full contracted volume is paid regardless of whether the link to the reference BZ actually evacuates the offshore generation rather than some other onshore flows.

#### **Direct Allocation: Quantitative illustration**

Based on the configuration shown in the introduction to section 3, we assume a Direct Allocation takes place in the hybrid system, eg encompassing the directions OBZ1→DK1 and OBZ1→BE. For each direction and hour, we compute what share of the flow is made up from OWF production, then sum up the total allocation value:

		2030	2030	2040	2040
		Without outage	With outage	Without outage	With outage
OBZ1-DK1 allocation	M€	3.30	22.02	11.67	61.10
OBZ1-BE allocation	M€	6.29	43.82	6.39	32.20
Total Allocation Value	M€	9.59	65.84	18.06	93.30
Revenue top-up from DA	%	1.05%	7.78%	1.43%	7.96%
CI OBZ-DK captured	%	226.68%	287.66%	86.89%	207.10%
Tot CI captured	%	86.55%	97.99%	54.02%	85.82%

The results across all simulated years and scenarios show a similar pattern to other options: around 1% revenue top-up for the offshore generator, and up to 8% with outage. Thus in this configuration, the direct allocation option provides the highest level of support when transmission capacity is scarce or unavailable.

In 2030, the direct allocation also captures the largest share of total CI out of all the options compared. This is due to the presence of non-negligible exports towards Belgium, which are accounted for in the total OWF contribution to CI, while other options only cover the link to HM. More specifically, the allocation breakdown across links shows that around 2/3 of the allocation stems from OBZ1-BE in that year. In 2040 the trend reverses and the values naturally align more with the other options.

## Joint ownership of transmission and generation

One option proposed by (THEMA Consulting Group, 2020) is the joint ownership approach, where a single legal entity owns both the network and generation assets. The entity brings together a consortium of Transmission owners - or alternatively a dedicated operator such as an offshore TSO or an ISO - and project developers to unlock the ability to internally redistribute the revenues accrued by the project as a whole (offshore revenues and CI) across stakeholders.

This option provides the flexibility to design tailored governance and redistribution rules based on each project specificities. What's more, redistribution is technically possible between all stakeholder categories (SO-SO, SO-OWF, OWF-OWF,...). The consortium also possesses a direct physical hedge with onshore markets in the form of its transmission assets.

However, the very concept of joint ownership poses a number of open issues. First and foremost, it goes against the foundational unbundling principle laid down in Article 43 of EU Directives 2019/944: *"the same persons are not entitled to directly or indirectly to exercise control over a transmission system operator or over a transmission system, and directly or indirectly to exercise control or exercise any right over an undertaking performing any of the functions of production or supply"* (European Commission, 2019). Through cross-subsidization, the costs of the merchant activities might be included in the regulated asset base under this model, which is undesirable.

In addition, non-discriminatory system operation and third-party access also become threatened. If new assets (offshore generation, interconnectors, P2X) were to connect and be excluded from the consortium, there would be clear incentives for discrimination against those assets. In theory, these problems might somewhat be mitigated under an ISO model with specific acceptance rules, but inherent concerns regarding unfair competition will still persist. Finally, as the grid develops and more participants take part in the joint ownership, the sharing arrangements may become increasingly complex to manage.

Overall the joint ownership solution presents regulatory challenges which question the fundamentals of the IEM and lead us to believe this option can hardly be satisfactory. If decision makers were to favour it regardless, the time required for such tedious legal changes would still drag its implementation in the short-term and hamper its usefulness as a transitional measure.

Note: On the other hand, some form of joint ownership can be envisioned in some cases between system operators only, when operating the interconnectors within the hybrid projects. For instance, past studies have showed examples where one TSO failed to recover investment costs when congestion income only occurred on other interconnectors. In such case, the TSOs could find a preventive arrangement by taking a 50/50 ownership share on both links. This is compatible with current CI sharing methodologies.

### Power Purchase Agreements & Guarantees of Origin (no CI)

Power Purchase Agreements (PPAs) are well-known bilateral energy contracts whereby a buyer agrees to purchase electricity from a generation asset at a fixed price for an extended period of time (10 to 25 years typically). Although they are not redistributing any congestion income, they fit in the current legal framework and do represent a viable option to support renewable development without relying on public fundings.

Indeed, with the progressive phase-out of direct renewable subsidies such as Feed-in Tariffs (FiT), PPAs have become over the years a tool of choice for project developers. They provide a cheaper cost of capital and a more stable cashflow model than a pure merchant asset. PPAs are essentially a special case of a CfD between the zonal market price and the

bilaterally agreed, fixed strike price. They can either be “physical” (onsite delivery to buyers, naturally not applicable to offshore assets) or “virtual” (off-site, financial swap only) and often bundle the transfer of Guarantees of Origin (GOs). These GOs act as a proof certificate that every MWh purchased by the buyer was produced from renewable sources, and it is also a tradeable product on dedicated markets.

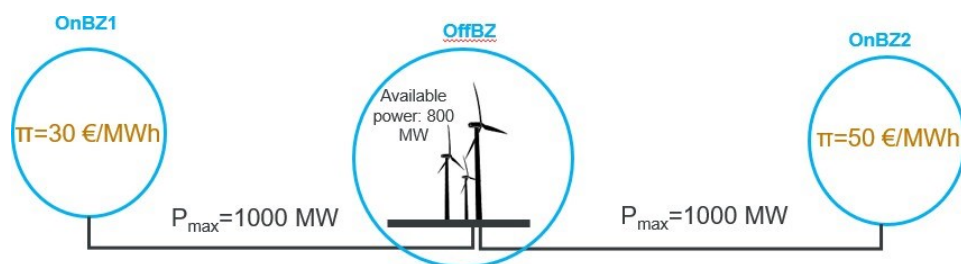
PPAs are mostly driven by Corporate demand but can also be contracted by utilities (energy suppliers) as part of a green retail portfolio offering. The PPA strike price could be set to reflect production and transmission costs, e.g. to include a congestion component. In this case, the TSO would keep the congestion income, and the offshore generator would be compensated by a third party: the PPA buyer.

Overall, the PPA represents a true market-based option to stabilize the revenues of the hybrid OWF in the long term. However, its outcome is quite unpredictable given that the strike price does not purely depends on market conditions (bilateral agreement). It is therefore difficult to assert whether the contract can fulfil its role to creating a level-playing field with onshore assets, especially when the latter can also enter into such agreements with their usually higher merchant prices.

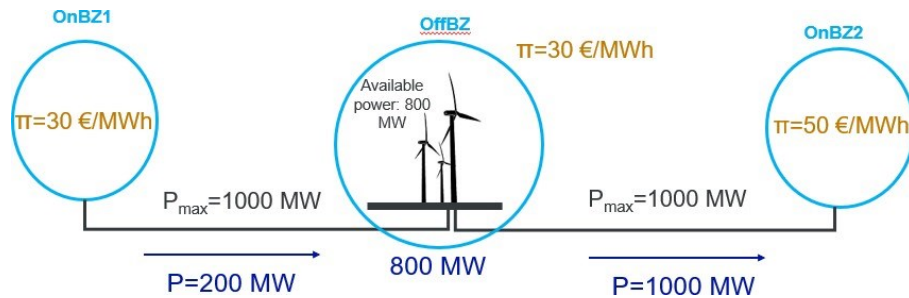
### C- Offshore Bidding Zones under tight transmission conditions

Through this report, we have mentioned on several occasion that the OBZ is particularly dependent on transmission and that a reduced availability of the latter can become a bottleneck for exports, thereby creating a volume risk for the offshore generator. It was also mentioned that under very restrictive transmission reduction events, there may be a price risk leading to decoupling with onshore BZs as well (and effectively pricing the OBZ at the most expensive local technology, i.e. zero). This appendix aims at clarifying how and when this can happen.

- Consider another simple configuration:

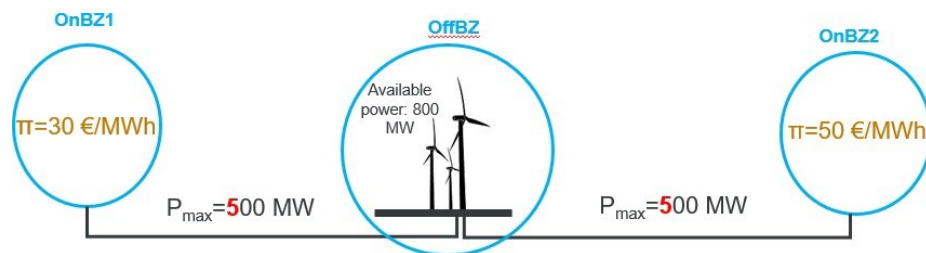


This would correspond to a “normal” situation where the generation and transmission planning have been coordinated such that there is enough interconnector capacity to evacuate the nominal wind production in any direction. The market results in this case are:

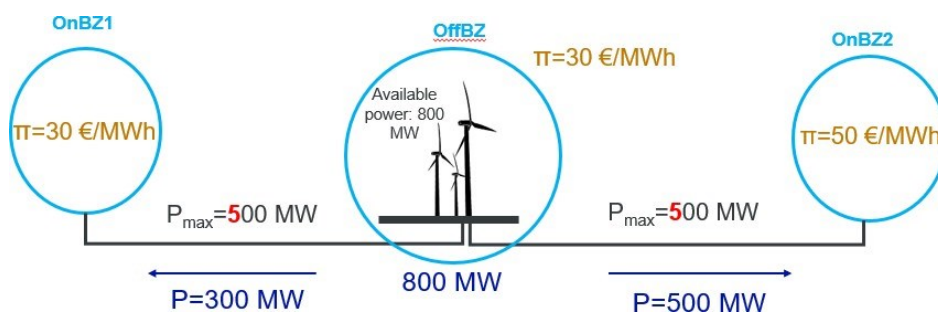


Assuming the OWF bids at 0€/MWh, the entire wind production is exported to relieve the high-price region (OnBZ2). The leftover transmission capacity is filled with some additional power from OnBZ1. Electricity flows are unidirectional, and the OffBZ price is coupled to that of OnBZ1 at 30€/MWh.

- Now let us assume a second situation that transmission has been temporarily reduced according to the following:

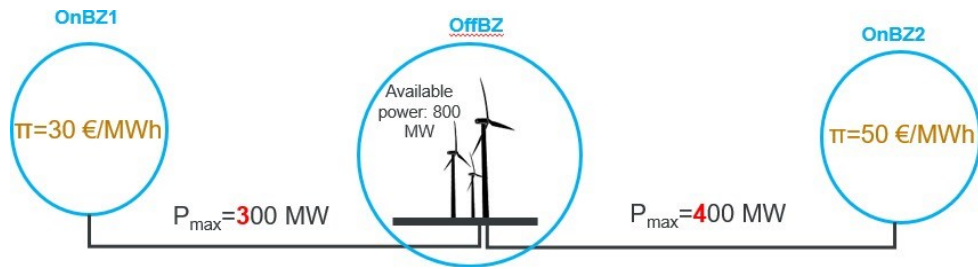


In this situation, there is still enough **total** transmission capacity to export the wind, but not all in one direction. The new market results become:

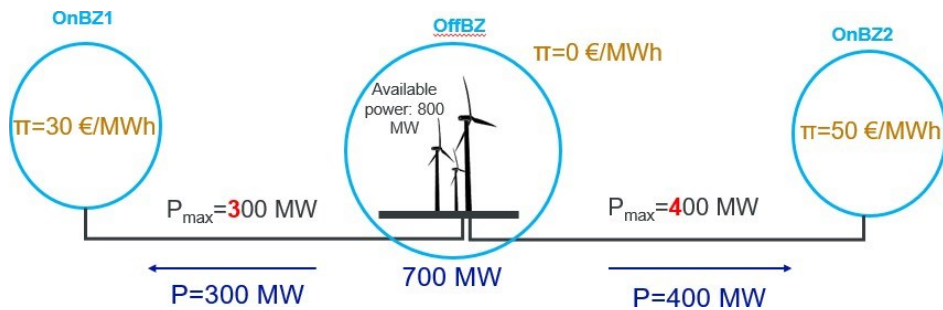


The system welfare is maximized when the cheapest resource (the OWF) remains dispatched at its maximum. But the OffBZ can no longer supply the 800MW solely towards OnBZ2, and start exporting towards both onshore zones instead (bidirectional flows). Prices remain unchanged and OffBZ is still coupled to OnBZ1 since the interconnector is not congested.

- Finally, let us assume a last situation with further reduction of the transmission capacity:

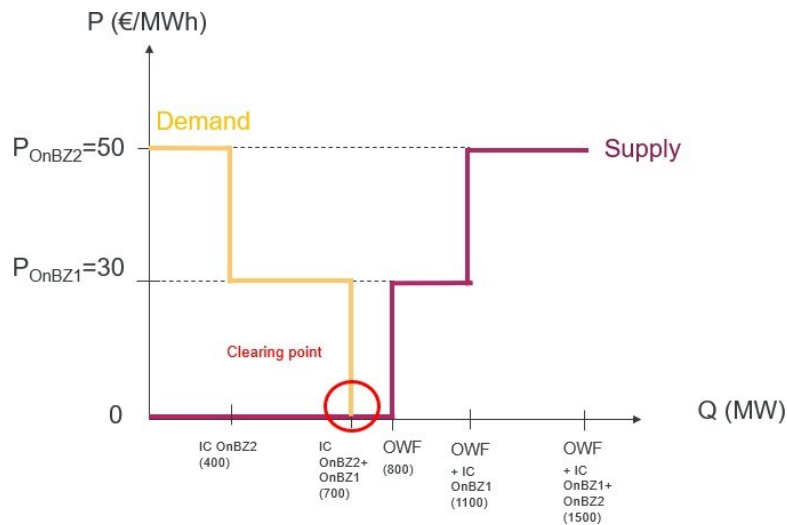


Here, the total transmission capacity is strictly lower than the available wind power in the OffBZ. The market results are:



The flow regime is still bidirectional, but the interconnector to OnBZ1 is now congested as well. What's more, the OBZ is not dispatched fully (100MW remaining) because there is no transmission capacity left for export. As Euphemia functions on the basis of marginal pricing, the price of the OffBZ is computed as the cheapest cost to supply one more theoretical unit of demand in that zone. Because all onshore resources have already been used efficiently to supply their respective demand, and because all hybrid transmission is already saturated at this point, this extra 1MW of demand in the OffBZ can only be supplied by the remaining OWF power that has not been dispatched yet. The OffBZ price thus becomes the bid price of the OWF, which should equal its short-run marginal cost (SRMC) of 0€/MWh according to economic theory. In other words, when not all the wind can be exported, the OffBZ is export-constrained, and its price becomes that of the most expensive local generator on site. This can be verified by plotting the demand-supply curve of the OffBZ:





The supply curve is made up of the available wind (assuming the entire production is valued at 0€/MWh), and of the imports of both onshore zones at the level of their respective interconnector capacity. Meanwhile, the demand curve is only composed of the possible onshore export valued at their zonal prices. The price and volume at the equilibrium are found at the intersection of both curves.

This example showed that, under extraordinary conditions when the total export capacity is strictly lower than the available wind power, OBZ prices may fully decouple from their onshore counterpart if these remain positive. Although we demonstrated that such events can occur, this should in principle not happen in practice under normal market operations.

In its discussion paper “Hybrid Offshore Project – Market arrangements” Eurelectric also develops different numerical examples with scarce transmission capacity. We provide a snapshot of one such example in the following figure:



Home Market			Offshore Bidding Zone			Effect
Congestion Rent (CR)	OG revenue	Total income	Congestion Rent	OG revenue	Total income	<ul style="list-style-type: none"><li>• Same dispatch = same generation costs</li><li>• Same Social Economic Welfare</li><li>• Redistribution of income between IC and OG owner</li></ul>
CR_A/B= 0	OG_A=2*5=10	CR= 0 OG=30	CR_A/H=2*5=10	OG=4*0=0	CR=30 OG=0	
	OG_B=2*10=20		CR_H/B=2*10=20			



Source: Eurelectric

Although we fully support the relevance of the example, here again we would like to clarify that:

- The case here where the entire wind power cannot be evacuated to a single direction already corresponds in our view to an exceptional situation (second configuration in our previous example) rather than a normal outcome of a well-designed generation and transmission planning. Even so, the probability that an offshore wind farm will generate at nominal capacity is very low, as the wind speed is variable and because the wake effect entails an effective derating. Consequently, if the grid connection between the offshore wind farms and the shores corresponds to the nominal capacity of the offshore wind farms, it will be rather rare to reach a situation when the available wind energy will correspond to the capacity of the grid connection.
- If the offshore wind farms has an availability of exactly the transmission capacity, as illustrated by the example above, the offshore electricity price is not necessarily equal to 0, but is indetermined (clearing point locatable anywhere on the vertical step of the demand-supply curve). In such cases, the current day-ahead market clearing algorithm normally then takes the average between the maximum and the minimum possible electricity prices. In the example above, it corresponds to 5 €/MWh, and not to 0 €/MWh.

## **D- Summary of first stakeholder seminar**

Date and location: Friday 26/11/2021 14:00-16:00, webinar

Presenters: ENGIE Impact (with foreword and closure from European Commission)

Number of participants: ~70 (ACER, ENTSO-E, EFET, TenneT, 50Hertz, RTE, Elia, WindEurope, Ørsted, Nordpool, EEX, Eurelectric, Iberdrola, RWE, Energinet, Vattenfall, Terna, Statkraft, EDP, CREG, CRE, BNetzA, DECC IE, Consentec, amongst others)

Content:



ENGIE Impact exposed the objectives of the assignment, the context and the more detailed problem statement. Specifically, the challenges related to the large scale deployment of hybrid offshore projects connected to more than one market were mentioned. The importance of “getting the prices right”, i.e. through an integration based on dedicated offshore bidding zones was reminded. While such dedicated offshore bidding zones increase the overall efficiency, ENGIE Impact argued that they may increase the risk profile of offshore hybrid generators and may therefore justify the introduction of a compensation mechanism. Particular focus was given to the case of transmission unavailability (outage), under which an onshore generator’s revenues are protected through an implicit CfD since the full production can still be sold on the market and physical curtailment is compensated later during redispatch. Meanwhile, in a dedicated offshore bidding zone, the generator bears the full risk of an interconnector unavailability (market curtailment and revenue reduction). An overview of possible support options were presented, namely under three main categories: ‘classic’ tools to improve investment incentives & profitability (PPAs, FiT, premiums, subsidies, etc.), options mentioned under past studies that were discarded in the course of the analysis (direct reallocation, joint ownership, highest onshore price) and the main bespoke options of interest (CI-CfD, CI-FTR and CI-ARR). Engie Impact then focused the rest of the presentation on a detailed description of the three bespoke options and on a first evaluation of their respective suitability.

#### Discussion:

A total of 45 minutes was allocated to feedback and open discussion. The relevant comments are listed below:

- ENGIE Impact assumed that onshore bidding zones are less/not exposed to interconnector outage risk. This may not always be true, as we already have smaller bidding zones in Europe (e.g. Nordics) that might face the same risk as OBZs. The question of eligibility must be further investigated.
- Several participants commented that line outage is not the only case of transmission unavailability and that the compensation regimes for these different cases should be investigated individually (force majeure, maintenance, reduced capacity allocation, etc.). In particular, when transmission becomes cross-zonal such as in the OBZ, the minimum 70% rule implies that there may be a 30% capacity derating on the hybrid interconnectors.
- The conclusions presented in past NTC-based quantifications may not hold under other network representations such as Flow-Based and the upcoming Advanced Hybrid Coupling (AHC). The impact of the latter should be taken into account in the analysis. Besides, examples with 3 or more connected markets could also be useful to assess if the impact of one line outage decreases.
- Discussion on whether costs can/should be borne by either tax payers or electricity consumers. The socio-economic difference between tariff setting and direct (classic) subsidies should be made more explicit. Member States are responsible for direct subsidies while grid tariffs are the common responsibility of TSOs and NRAs.
- Should ARR holders be allowed to participate in FTR auctions? If so, then the possibility of gaming & collusion increases, but if not, then the participation in the FTR auction may drop substantially (thus also price and ARR revenues).

- The options investigated require changes in EU legislation. It seems of high importance to see what the effects would be on the current separation of costs and financing related to the grid on one side, and subsidies for generation assets on the other side. Subsequently a mixing of these monetary streams might lead to infringement on current decision powers of regulatory authorities.
- The options analysed all consider the redistribution of congestion revenues. Yet, it should be further justified why this should be considered above all other options such as classic support schemes. There are issues with each of the options, including the use of revenues destined for network investment being used to support generation and the issue of how to divide costs between Member States for cross-border projects.

## **E- Summary of second stakeholder seminar**

Date and location: Tuesday 29/03/2022 13:30-15:00, webinar

Presenters: ENGIE Impact (with foreword and closure from European Commission)

Number of participants: ~50 (ACER, ENTSO-E, EFET, TenneT, 50Hertz, RTE, WindEurope, Ørsted, Eurelectric, Statkraft, EDP, CREG, CRE, DECC IE, Consentec, amongst others)

### Content:

ENGIE Impact reminded participants the objective of the project. The main aspect of this second workshop was to show how the problem statement and the conclusions were refined, in particular thanks to the feedback gathered during the first seminar. A first point of attention was to emphasize that OBZs are economically efficient, and that the shift of economic surplus alone cannot justify the implementation of reallocation mechanisms in favor of offshore wind farms. A support mechanism based on the redistribution of some congestion income should necessarily cover a market failure or a discriminatory treatment of offshore wind farms. The central case of transmission outage was expanded to consider five situations: uncoordinated grid and generation planning, force majeure & emergency, maintenance, reduced capacity allocation and cross-border redispatch. ENGIE Impact then defended that only operational reductions in allocated transmission capacity represents a specific risk for OWFs that is currently not addressed, with significant adverse effects on profitability. A refined view on the bespoke options was then presented, with the main message being that while CI-FTRs are preferred, none of the options fully address the identified risk. ENGIE Impact then proposed an alternative option: the Transmission Access Guarantee (TAG). The TAG entails a compensation paid by TSOs when the export capacity of the OBZ drops below the installed wind capacity due to operational capacity reductions. As a conclusion, ENGIE Impact expressed its preference for mechanisms that do not create significant market distortions, and for the TAG as a safeguarding measure. If/where AHC is implemented, the applicability of the TAG will be less frequent, without compromising its relevance as a support mechanism.

### Discussion:

A total of 30 minutes was allocated to feedback and open discussion. The relevant comments are listed below:

- The improvements of the study were well received, with the positive note that the risks were more precisely identified and that the conclusions became more operational.
- The solutions proposed address only a minor part of the main issue faced by hybrid projects, which is profitability of the overall long-term business case.
- The subsidy regime needs to facilitate both a level playing field for generators, and commensurate return on investment. The discussion around “leveling” actions is important when considering the distance to shore/water depth, as some OWFs (e.g. in deep water) may have a structurally higher cost than shallow water farms. Moreover, if different subsidy and funding regimes are used for OWFs connected to the same “island” then there may be competitive advantage for one farm to deliver in favor of another.
- Other important factors which could lower OWF revenues in an OBZ structure should also ideally be quantified: market-based curtailments due to negative prices in neighbouring bidding zones, reduced feed-in due to flow-based grid situations favouring other in-feeds to increase the overall welfare and feed-in prognosis failures.

**ENGIE Impact would like to thank all the participants for their constructive feedback and for sharing their views on the study.**

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