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Market Arrangements for Offshore Hybrid Projects in the North Sea

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THEMA

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Contact: Thomas Bregeon

E-mail: Thomas.BREGEON@ec.europa.eu

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B-1049 Brussels

Market Arrangements for Offshore Hybrid Projects in the North Sea

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Brief summary

This report considers the appropriate electricity market arrangements to be applied to offshore hybrid projects, i.e. projects that combine offshore generation capacity with transmission capacity connecting two or more onshore bidding zones. Two options are examined in detail: the use of Offshore Bidding Zones that reflect structural congestion and the extension of onshore Home Market zones to cover offshore generators. Dispatch modelling of these two options is conducted for the period to 2050 for the North Sea region and a detailed theoretical assessment of the options' performance against a wide variety of criteria is undertaken.

Ultimately, we conclude that the use of Offshore Bidding Zones is likely to be more efficient and resilient to future changes in the offshore network and the power system more generally. This approach is also more consistent with current regulatory principles and less likely to result in undue discrimination between market participants. The use of offshore bidding zones may, however, be less effective in securing commercial investment in offshore generation as part of hybrid projects due to a tendency to allocate a lower share of aggregate project revenues to generation owners. Multiple options for the redistribution of revenues are therefore also discussed.

About THEMA Consulting Group

Øvre Vollgate 6
0158 Oslo, Norway
Company no: NO 895 144 932

THEMA Consulting Group is a Norwegian consulting firm focused on Nordic and European energy issues, and specialising in market analysis, market design and business strategy.

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1 Options and Assessment Approach

Hybrid projects combine offshore generation and cross-zonal transmission capacity.[1] *This allows for lower cost deployment by reducing the need for physical infrastructure. In this report, we consider the appropriate market arrangements for such projects. Two fundamental options are examined: the Home Markets model in which the offshore assets are included in an existing onshore bidding zone, and the Offshore Bidding Zones model, in which bidding zones reflect structural congestion and therefore entirely new offshore bidding zones might be created. In the remainder of the report, we consider the challenges facing both options and possible means of resolving them before ultimately conducting an assessment of both options against a wide range of assessment criteria.*

1.1 Background on Hybrid Projects

This study seeks to understand the implications of applying different electricity market arrangements to so-called hybrid projects. These projects effectively combine offshore generation capacity with transmission capacity connecting two or more onshore bidding zones. In this way, hybrid projects combine the capabilities of a traditional interconnector, i.e. enabling the transmission of power between bidding zones, with the ability to generate power offshore and transport it to the onshore power network.

Hybrid projects allow for the more efficient deployment of offshore generation and transmission capacity relative to the use of discreet interconnector cables and direct-to-shore connections for offshore generation. In particular, they allow for lower cost deployment by significantly reducing the need for physical infrastructure, notably reducing the length of offshore cabling required and the need for converter stations. They also enable the more efficient use of maritime space and, in doing so, help to reduce environmental impacts of offshore development.

1.2 Approach and Report Structure

Power market arrangements are complicated and supported by a number of dedicated regulations and network codes. To help focus our work, we began by identifying the challenges that hybrid projects appeared to face in relation to the market design.

Following this review, it became apparent that these challenges are highly dependent on the fundamental choice of bidding zone design. This choice determines how the generation assets are treated as part of the market clearing solution, potentially affecting their dispatch behaviour. It also has several important knock-on effects, for example in determining the imbalance price they are likely to face.

Given the importance of bidding zone design for many of the other potentially relevant elements of the market arrangements, we have therefore structured the report around the choice of bidding zone design. In section 1.3 below, we describe these options in further detail. We also identify two options, the so-called Home Markets and Offshore Bidding Zones options, as worthy of further consideration. Chapter 2 of the report details the challenges that will be faced under these different options and explores ways in which the market arrangements might be adapted to address them. In doing so, it seeks to present a more complete view of market arrangements under the two options. Chapter 3 details modelling of the bidding zone designs. The modelling provides estimates of the scale of the impacts and some useful demonstrations of the implied market dynamics. Chapter 4 then brings this all together into an assessment of the Home Markets and Offshore Bidding Zones options, highlighting the distinctions between them. Chapter 5

[1] Note that the terms 'hybrid project' and 'hybrid asset' are not interchangeable. Consistent with the use of the term 'hybrid asset' in European regulation, a hybrid asset refers to "offshore electricity infrastructure with dual functionality […] combining transport of offshore wind energy to shore and interconnectors" (Recital 66, Regulation (EU) 2019/943). It is assumed to cover only the relevant transmission infrastructure. The term 'hybrid projects' is used to refer to both transmission infrastructure and any associated offshore generation infrastructure.

considers the practicality of regulatory governance and system operation under the Offshore Bidding Zones option, given that this option could allow for multinational bidding zones, and sketches workable arrangements for both. Chapter 6 concludes by summarising the assessment of the options and provides recommendations.

The report also includes an annexed section that sets out other potential governance and regulatory challenges associated with the realisation of mass offshore renewable generation deployment that are beyond the scope of this study. The points raised in this section are drawn largely from the discussions we have had with stakeholders over the course of the project and are not limited to a consideration of hybrid projects or the associated market arrangements. In effect, this section provides a useful reminder of the other issues worthy of consideration.

1.3 Options

Bidding zones are used in European and other power markets to group together generators and consumers for the purpose of clearing the power market. In general, the market does not distinguish between locations within a bidding zone and, as a result, all participants in the same zone are exposed to the same market price. In effect, the choice of bidding zone design for hybrid projects determines the apparent location of the offshore generators and consumers as seen by the power market.

There are four main bidding zone options for hybrid projects. These are set out in Table 1 below. Note that this taxonomy of options effectively matches the options originally identified by the North Seas Countries' Offshore Grid Initiative[2], as well as those considered more recently in reports for the European Commission and by industry.

Table 1: Bidding Zone Options

Home Markets	Generator/consumer is added to one existing onshore bidding zone based on its connection points to the mainland network
Offshore Bidding Zones	Bidding zones are defined to reflect structural congestion in the network, potentially resulting in the creation of new bidding zones that only include offshore generators/consumers
Dynamic Bidding into High-Price Zone	Offshore generators' bids (consumers' offers) are dynamically placed into the existing, connected bidding zone that has the highest price
Dynamic Bidding into Low-Price Zone	Offshore generators' bids (consumers' offers) are dynamically placed in the existing, connected bidding zone that has the lowest price

An initial assessment of these options concluded that the dynamic options faced several inherent and significant regulatory and operational challenges, discussed below.

[2] Now the North Seas Energy Cooperation (NSEC) group

From a regulatory perspective, the use of dynamic bidding zones conflicts with two fundamental regulatory principles:

- the aim to ensure non-discriminatory treatment of market participants (CACM Art. 3.e); and,
- the need for bidding zone stability (CACM Art. 33.1.c).

By reconfiguring bidding zones based on price, dynamic bidding zones would systematically discriminate in favour of or against offshore generators and consumers relative to onshore market participants. For example, assigning offshore generators and consumers to the high-priced zone would systematically benefit offshore generators and harm offshore consumers relative to onshore equivalents and without good cause.

The dynamic bidding zone approach is also at odds with the fundamental European market model, in which bidding zones are stable across capacity calculation timeframes. Article 33 of the Guideline on Capacity Allocation and Congestion Management (CACM) establishes the criteria to be considered as part of reviews of bidding zone configuration. Paragraph 1.c notes several criteria "in respect of the stability and robustness of bidding zones", including "the need for bidding zones to be consistent for all capacity calculation time-frames". The dynamic bidding zone option would effectively imply changing zones *ex post*, as a result of the market clearing price.

This inherent instability may also give rise to operational challenges. Specifically, the dynamic approaches implicitly assume that the ranking of prices in connected zones is unaffected by the offshore generation and consumption. However, this need not be the case. It is entirely possible, for example, that attempting to place offshore generation in the high-priced zone will cause this zone's price to drop such that it becomes the low-priced zone. While rules can be devised to avoid situations in which the clearing solution is indeterminable, such cases highlight the perversity of trying to set bidding zones based on prices, when these prices themselves depend on the bidding zone definitions.

Given these challenges, it was decided that there was very little chance of the dynamic options representing a preferred market design and, as a result, they were eliminated from further consideration.

The rest of this report focuses on the Home Markets and Offshore Bidding Zones options, the challenges they bring and what can be done about them, and ultimately which option is likely to represent the preferred set of market arrangements for hybrid projects. However, it should be noted that our further consideration of these options does not imply that one or both are consistent with existing law or regulatory principles. In particular, restricting cross-zonal capacity to deal with network constraints within a bidding zone, as potentially implied by the Home Markets option, may not be compatible with Article 102 of the Treaty on the Functioning of the European Union, as it arguably unfairly discriminates between network users.[3] As such, the set of legally viable market design options may be more limited than considered as part of this assessment.

[3] This issue has been previously considered as part of legal proceedings involving TenneT and Svenska Kraftnät.

2 CHALLENGES AND POSSIBLE RESPONSES

The Home Markets and Offshore Bidding Zones options give rise to several challenges, some of which can be addressed through further modifications to the current market arrangements. The Home Markets option is liable to result in significant dispatch inefficiency and renewables curtailment unless offshore injections are given priority access to offshore transmission capacity. Priority access is therefore assumed to form an integral part of the Home Markets option. Given this assumption, the options are fairly similar in terms of their dispatch efficiency. The Offshore Bidding Zones option is liable to distribute revenues differently between generation and transmission owners. Given regulatory restrictions on the use of transmission revenues, the Offshore Bidding Zones option might make it harder to construct a viable investment case for hybrid projects. Several options to address this challenge have been identified, but most of them are likely to require regulatory changes.

2.1 Overview of the Challenges

This chapter details the various challenges associated with applying the Home Markets and Offshore Bidding Zones options to hybrid projects. These challenges have been identified based on a consideration of the effects of implementing the two options. Specifically we have considered whether there exist obvious tensions in delivering against the assessment criteria, discussed further noted in section 4.1, or else obvious practical difficulties associated with the implementation and operation of the relevant option.

Four key challenges are discussed:

- Priority Access – How access to the offshore transmission capacity is split between offshore injections and cross-zonal flows
- Cross-Zonal Capacity Calculation – How the transmission capacity available to the market is calculated
- Balancing and Redispatch – Balancing incentives and the practicalities of balancing and congestion management for hybrid projects
- Revenue Distribution and the Efficiency of Investment – How hybrid project revenues are shared and the implications for investment efficiency

The next two sections detail these challenges as they relate to the Home Markets and Offshore Bidding Zones options respectively. The Offshore Bidding Zones section also has a short subsection on price manipulation.[4] In each case, we set out the fundamental nature of the challenge and consider whether additional modifications to the current market design might be used to help address it. In doing so, we occasionally identify such modifications and incorporate these 'fixes' into the definition of the overarching option. In this way, these sections provide a more comprehensive view of the market arrangements under the two options, while also explaining the rationale for the other changes assumed.

The chapter concludes with a section that summarises the additional modifications that are assumed to form a part of the Home Markets and Offshore Bidding Zones options.

2.2 Home Markets

2.2.1 Priority Access for Cross-Zonal Trade

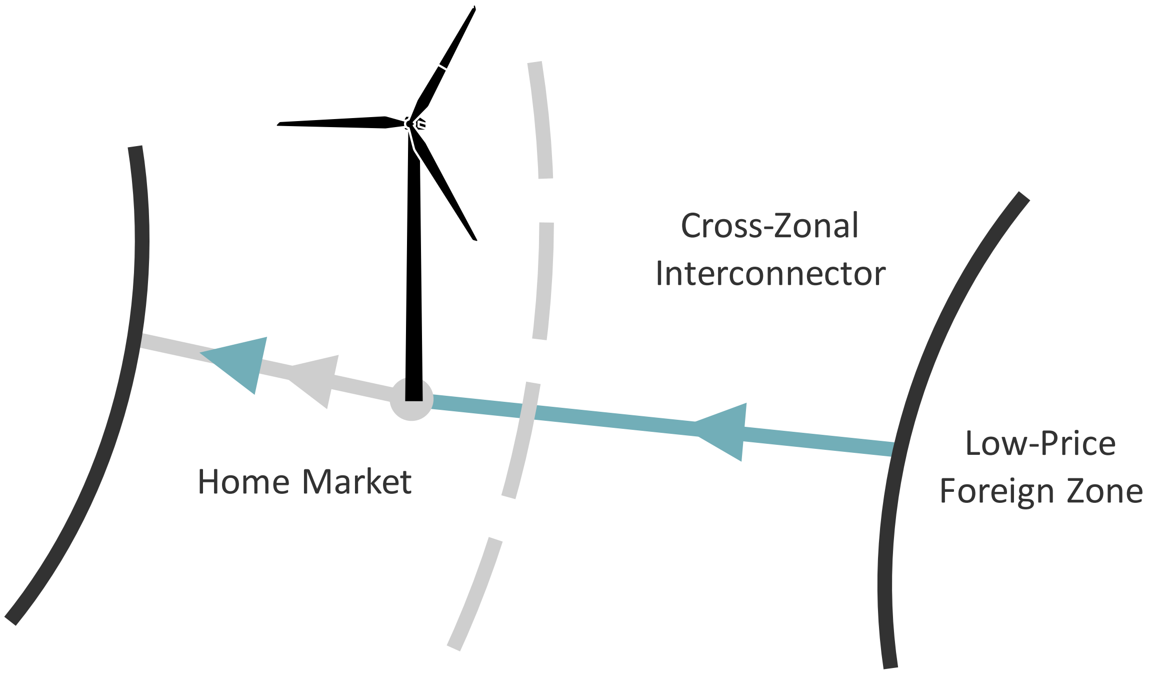
European regulation is based on the principles that transmission access should be determined by efficient dispatch and that electricity should flow from lower to higher

[4] We assume that Home Market bidding zones are sufficiently large that the issues of market power in small bidding zones that are discussed in this section will not be relevant under the Home Markets option.

priced areas. In order to prevent discrimination against cross-zonal dispatch, for example as a means of resolving internal congestion, current regulation prioritises cross-zonal flows from low- to high-price areas, as described further below. Under the Home Market arrangements, in which the offshore generator's injections become internal flows, this prioritisation of cross-zonal flows could result in the need to curtail the offshore generator's output in order to free up transmission capacity for imports. In the event that offshore generation is cheaper at the margin than importing power, this curtailment will result in economically inefficient dispatch.

There is an established principle in electricity legislation that the maximum capacity on interconnectors should be made available to the market. Article 16(8) of Regulation (EU) 2019/943 established a target for assessing compliance with this principle and states that "Transmission system operators shall not limit the volume of interconnection capacity to be made available to market participants as a means of solving congestion inside their own bidding zone". It also makes clear that TSOs shall be deemed to be in compliance with this requirement where at least 70% of capacity is made available for cross-zonal exchanges.

Figure 1: Example of Priority Access for Cross-Zonal Trade



An example of the practical challenge this poses to the Home Market arrangement is shown in Figure 1 above. Here, the offshore generator forms a part of the home market on the left. Power is imported into this zone from the low-priced zone on the right via the hybrid project. As can be seen, both these imports and the injections from the offshore generator flow along the grey cable on the left.

Article 16(8) requires, at the very least, that 70% of available capacity on the teal interconnector be made available for trade, in this case for imports into the home market. In practice, this means that sufficient capacity to transfer these import flows must be kept available on the grey cable linking the offshore generator to its home market and, therefore, that any generation from the offshore generator that cannot be accommodated by the residual capacity on the grey line must be curtailed.

Given that the economic cost of marginal power produced in the low-price foreign zone is likely to exceed the economic costs of the wind power that was curtailed (which is essentially available for free), such curtailment is likely to be, though not necessarily, economically inefficient.

In general, because the flows between the offshore generator and the home market are classed as internal under the home market setup and such flows are subordinate to cross-zonal flows under the current regulatory setup, the system will function inefficiently, likely reducing the welfare of European citizens. This welfare loss is either the direct result of the inefficient dispatch described above or else the inefficient investment signals for hybrid infrastructure that result from the potential need to curtail the offshore generator. For example, the grey landing cable may be oversized to try and limit competition with cross-zonal flows and the resultant curtailment of the offshore generator, thereby undermining some of the potential efficiencies associated with hybrid projects relative to the use of separate direct-to-shore connections. Alternatively, the project might simply be realised as separate generation and interconnection projects.

Aside from altering the structure of the transmission assets to mitigate the problem, or accepting the need to create an offshore bidding zone, one could alternatively seek to enable the prioritisation of offshore injections. We consider two possible options to do so below: an Article 63 exemption and new regulation designed specifically to grant priority access. It should be noted that although a blanket prioritisation of offshore injections will alleviate the serious dispatch inefficiency issue explained above, it also gives rise to other potential dispatch inefficiencies, discussed further in section 4.2.

Article 63 exemption

Article 63 of Regulation (EU) 2019/943 allows for certain time-limited exemptions for new merchant DC interconnectors. Importantly, it allows for exemptions from the 70% minimum discussed above. Although Article 63 focuses primarily on exemptions for merchant interconnectors, recital 66 states that:

> *"Offshore electricity infrastructure with dual functionality (so-called 'offshore hybrid assets') combining transport of offshore wind energy to shore and interconnectors, should also be eligible for exemption such as under the rules applicable to new direct current interconnectors. Where necessary, the regulatory framework should duly consider the specific situation of those assets to overcome barriers to the realisation of societally cost-efficient offshore hybrid assets."*

As such, one can reasonably assume that this exemption route is also available to hybrid projects.

Although this exemption route may provide a near-term solution to the dispatch inefficiency resulting from priority access for cross-zonal trade flows under the Home Markets option, it falls short of creating future-proofed market arrangements that can support enduring hybrid assets and of providing a predictable regulatory environment for investment.

In particular:

- The exemptions are time limited. Although there is no further detail on how long such exemptions may last (and the decision-making practice has seen exemptions going up to 20 or even 25 years), it is apparent that such exemptions are not intended to represent an enduring element of the market arrangements. However, the core problem of competition for scarce transmission capacity between offshore injections and cross-zonal flows is not a transitory one. As such, this exemption approach does not seem capable of providing a future-proofed design.
- The exemption route, by its very nature, implies that these projects should be the exception rather than the rule and adds a layer of regulatory risk. Relying on the use of Article 63 exemptions would mean that hybrid projects depend on a seemingly fragile regulatory compromise and case-by-case decisions would make hybrid projects far less attractive than direct-to-shore connections in terms of the regulatory risks involved.

- The relevant exemption can only be provided if various conditions are met. These include requirements that the interconnector be new or else have its capacity significantly increased. The interconnector owner must also be legally separate from the system operator in the relevant system. Although none of these requirements represents a massive hurdle, they are likely to frustrate the integration of existing interconnector assets into hybrid projects.

New priority access

In light of the seriousness of the dispatch efficiency problem absent any further adjustments to the market design and the deficiencies associated with a reliance on Article 63 exemptions, we therefore assume that hybrid generation assets would need to be given general priority network access over cross-zonal flows. This priority forms an integral part of the Home Markets design and is assumed to be an enduring part of the associated arrangements. It must be noted that establishing such priority raises several legal and regulatory challenges, noted below.

Critically, the priority that we assume is afforded to offshore hybrid generation assets could be considered discriminatory and is potentially incompatible with European law. Earlier legal proceedings looking into the restriction of cross-zonal capacities to resolve internal network congestions have considered whether such activity is consistent with Article 102 of the Treaty on the Functioning of the European Union, which concerns the application of similar provisions to providers throughout the internal market. It is conceivable that such prioritisation would be illegal under the Treaty.

Even if the creation of priority access were legal, implementing it would require potentially significant amendments to existing regulations. This is because the existing regulation governing priority dispatch, even if amended such that it could be applied to a large-scale offshore renewable generator, would fail to grant the necessary priority over cross-zonal flows. A full assessment of the necessary regulatory amendments has not been conducted as part of this work. However, we note that amendments could potentially be required to Articles 3, 12 and 16 of Regulation (EU) 2019/943 and to Article 6 (on third-party access) of Directive (EU) 2019/944, possibly among others.

Given these legal challenges, granting priority access is likely to harm the overall political acceptability of the Home Markets approach, as discussed in section 4.7. However, we do not consider the Home Markets option to be viable for hybrid projects unless some mechanism can be used to prevent the prioritisation of cross-zonal trade leading to the curtailment of offshore generation.

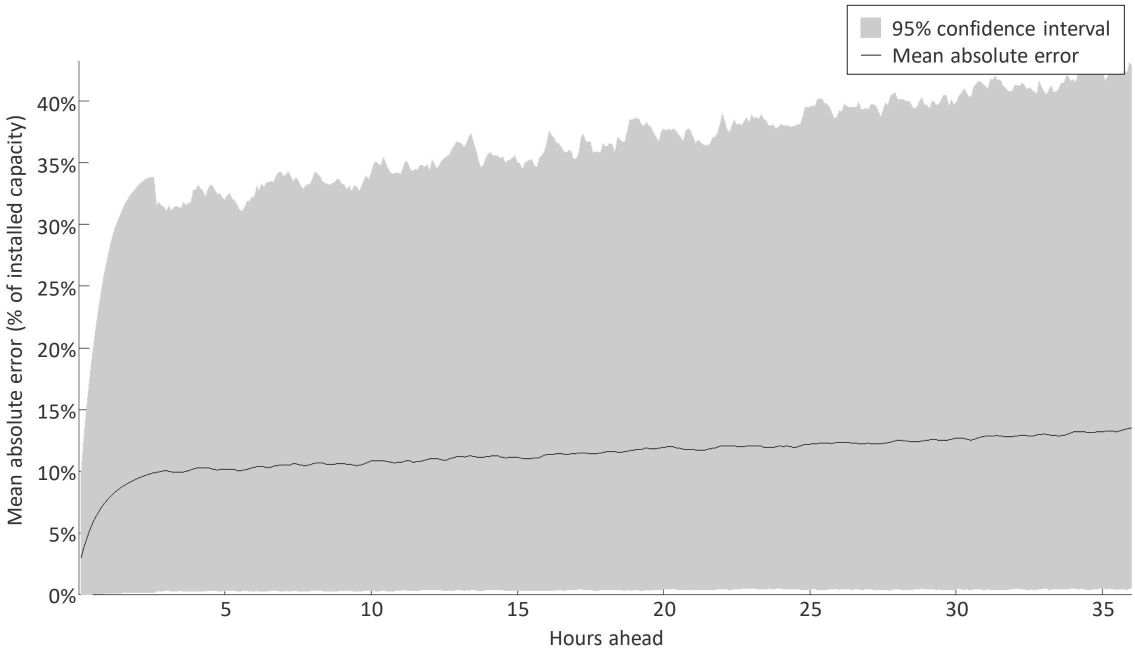
It is also important to note that, although the assumed priority access helps to improve dispatch efficiency, it does not fully alleviate such inefficiency under the Home Market approach, as described further in section 4.2.

Cross-Zonal Capacity Calculation

Under the Home Markets approach, scarce offshore transmission capacity must be divided between offshore injections and cross-zonal flows. Granting offshore injections priority access to this capacity would establish a clear rule for the allocation of this capacity, but does not eliminate the practical challenge of identifying the capacity available for cross-zonal exchanges. Critically, where offshore injections are granted priority, this remaining capacity available for cross-zonal trade will be heavily dependent on the volume of these offshore injections. Looking at Figure 1 above, for example, the available import capacity to the Home Market is capped by the residual capacity available on the grey line after injections from the offshore wind generator. The volume of offshore generators' injections will not be known with certainty ahead of real time and, as a result, the TSO responsible for calculating the residual cross-zonal capacity available for trade will be reliant on projections of offshore generation.

Figure 2 below, using data provided by Energinet, shows the mean absolute size of offshore wind forecasting errors for offshore wind sites as a share of installed capacity and how this error changes as we approach real time. The data implies that estimates of offshore generation made more than a day ahead of real time are likely to be off by slightly more than 10% of installed capacity on average. The confidence interval, shown in grey, also makes clear that the error can be significantly larger, sometimes in excess of 30% of installed capacity. These forecasting errors imply the need for corrections to the day-ahead dispatch solution of this order of magnitude. Such 'corrections' might come about through a combination of trading in the intraday market and redispatch by the TSO.

Figure 2: Forecast Errors for Offshore Wind Generation Against Time Ahead of Real Time



Source: Energinet

Arguably, the TSO is not best placed to estimate the generator's injections, having no core competency in the estimation of the generation asset's expected output nor direct knowledge of the operating status of the generator.

The TSO's financial incentives to err on the side of over or under-estimating the capacity available for cross-zonal trade will depend on the specifics of the regulatory framework in which it operates. In general, allowing for greater cross-zonal exchanges might enable a transmission owner to realise greater congestion income, but EU regulation effectively requires that these revenues be earmarked for use in facilitating additional cross-zonal trade or else returned to consumers via tariffs. Restricting the volumes available for cross-zonal trade is less likely to result in a situation in which there is congestion on the transmission assets that then needs to be resolved through costly countertrade or curtailment.

A risk-averse TSO might, therefore, act to restrict the capacity available for cross-zonal trade by systematically overestimating the injections from offshore generation, thereby effectively increasing its reliability margin. By systematically estimating large injections from the offshore generator, the system operator can justify allocating large volumes of available transmission capacity to accommodate these flows, and by extension, justify allocating smaller residual volumes for cross-zonal flows. Assuming, as we do, that the hybrid project is exempted from the requirement that at least 70% of transmission capacity be made available for trade, such behaviour would not be illegal. Erring on the side of overestimating offshore injections will reduce the likelihood that the offshore generator's actual output will exceed the transmission capacity allocated to accommodate its flows and reduce instances of congestion on the transmission network that the system operator will be financially liable for resolving. Importantly, this result stems from the assumption that the system operator has asymmetric financial incentives from under and over allocating capacity for cross-zonal trade, with no financial benefit stemming from higher congestion incomes but a real financial cost from higher redispatch and counter trade costs.

Allowing generation owners to define residual capacity

An alternative option would be to include generators' expected output directly in the capacity calculations, thereby benefiting from their superior information and relevant expertise. This approach might open up new opportunities for market manipulation, however. Although these challenges can be significantly mitigated by requiring generators to trade in line with their stated expectations and by releasing any capacity made available in the intraday timeframe as part of intraday auctions, it is far from clear that amending the capacity calculation process to accommodate information from generators can be justified.

The crux of the problem is that if generators' stated production expectations are used mechanistically to determine the cross-zonal capacity made available to the market, these generators will understand their ability to influence available cross-zonal capacity and may therefore be able to manipulate market conditions to their advantage. Consider the case, depicted in Figure 1 above, in which the generator is feeding into its home market alongside cross-zonal imports. By over-estimating its production, the generator can effectively restrict the capacity available for imports into its home market and thereby potentially increase the price it receives for its generation. This strategy relies significantly on the generator's ability to signal expectations about its generation for the purposes of capacity calculation that are distinct from its own trading position. If the generator were forced to offer wind volumes into the day-ahead market in line with its high stated expectations, this would exactly offset the resultant reduction in capacity available for imports, and there would be no net price effect day-ahead. However, the ability to link the generator's expectation to its trading position is somewhat complicated by the timings of the market, since the cross-zonal capacity available to the market is calculated and published in advance of the day-ahead market's closing.

Even if the generator's 'expectations' are tied to its trading position, the generator may still have some residual incentive to oversell into the day-ahead market under the current market arrangements, although the benefits of this strategy may be more uncertain. Specifically, the value of additional cross-zonal capacity released for continuous intraday trade does not accrue to the transmission owner, through congestion incomes, but is effectively shared among the energy traders that make use of this capacity. By overestimating its production day ahead and then buying back power through continuous intraday trade, the generator could potentially force the system operator to hold and then release cross-zonal capacity intraday and then potentially capture the value of this capacity by buying cheap power from the foreign bidding zone during continuous trading. This strategy relies on the current continuous trading arrangements. Importantly, releasing any capacity that becomes available through planned intraday auctions would eliminate this problem and close this opportunity for market manipulation.

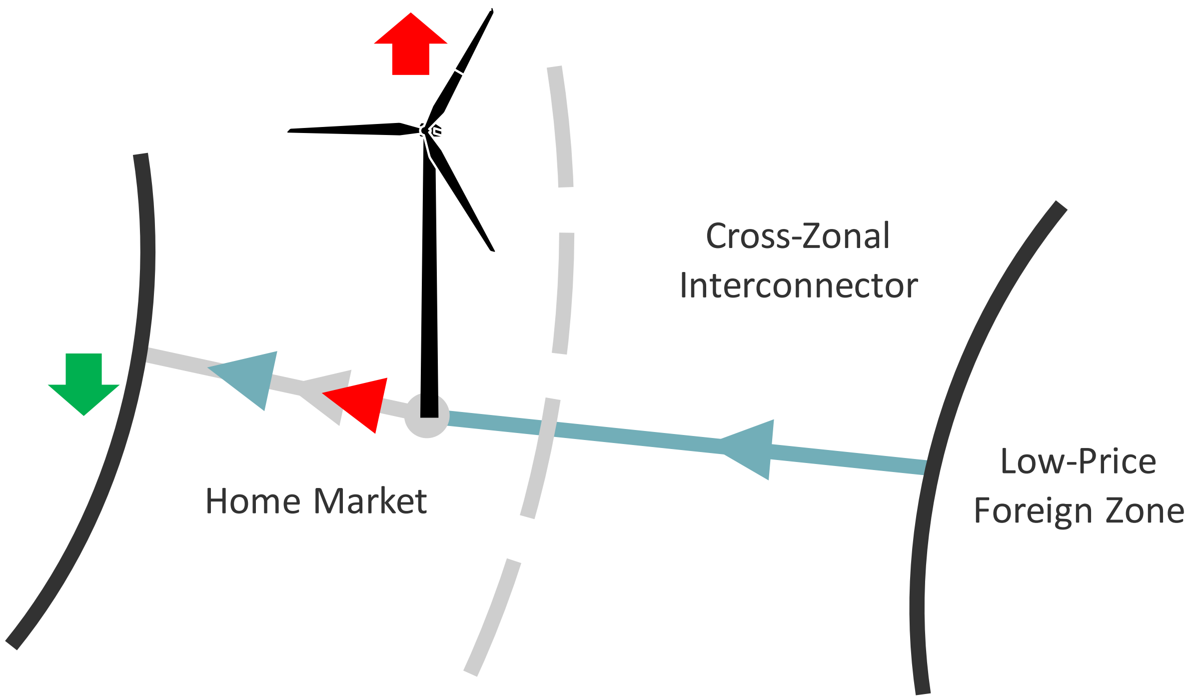
Ultimately, using market design to directly incorporate generators' expectations into the capacity calculations made ahead of the day-ahead market seems premature, given the risks and challenges in doing so. System operators can anyway work with generators to improve their forecasting accuracy without the need for these generators to be formally involved as part of the market design. Potentially, more sophisticated representations of available cross-zonal constraints that account for these generators' dispatch positions might be usefully developed as part of the market-clearing algorithm, thereby improving the accuracy of the day-ahead solution and reducing the need for corrections intraday. However, we assume that, in the first instance, system operators are able to realise most of the benefit of generators' improved information by working in close partnership with these generators without the need for further reforms to the regulatory environment.

2.2.2 *Balancing and Redispatch*

Under the Home Markets option, the transmission asset(s) linking the generator(s) to the home market become a part of the relevant bidding zone's internal transmission network. The physical limits of this transmission asset are, therefore, not visible to the market arrangements governing intraday day trade and, potentially, imbalance settlement. As discussed below, the balancing behaviour of the generator will, in many cases, fail to support the efficient and secure operation of the power system and TSOs will often be required to intervene to enable balancing after the day-ahead stage.

To see why this is the case, imagine the scenario depicted in Figure 3 below. Here, the offshore generator has realised after the closure of the day-ahead market that it will generate more power than anticipated. To balance its position, it will either sell this power intraday within its home market or, if it cannot do so and where the imbalance settlement arrangements allow, seek to net this expected imbalance with another party within the same balancing group. In both cases, the effect of this will be equivalent to turning down generation in the home market. The generator could also seek to curtail its own output, but we assume that the power price will generally be positive and, therefore, that the market will generally not incentivise the generator to do so.

Figure 3: Example of the Balancing Challenge under the Home Markets Option



Unfortunately, while these actions might help to ensure an overall balance of supply and demand for power within the home market, the resultant dispatch solution is not feasible. Again, the problem lies with the grey transmission cable connecting the wind generator to its home market. The day-ahead dispatch solution has already allocated the full capacity on this line to the combination of cross-zonal imports and the originally anticipated injections from the wind farm. Further injections cannot therefore be accommodated without a reduction in cross-zonal flows – the implied reduction in generation in the home market does nothing to alleviate the congestion problem on the grey line.

It is worth noting that this tension is not necessarily unique to hybrid projects. Rather, it results from the fact that a variable generator is effectively competing for scarce transmission capacity with cross-zonal flows. One could imagine the same picture as above in which the offshore wind farm is replaced with an onshore windfarm. Rather, the issue is that hybrid project asset configurations and transmission constraints, combined with the assumption of priority access for large variable generation, make this issue more severe. If the generator didn't have priority access, current regulatory practice would require that the excess wind generation be curtailed to maximise the transmission capacity available for cross-zonal trade. Similarly, if the generator wasn't effectively merged with the interconnector asset, but a part of a meshed transmission network, it would be less likely that the transmission capacity was fully utilised as part of the day-ahead dispatch solution, potentially allowing for a larger buffer before additional flows exceeded available capacity.

Below we discuss a variety of possible modifications to the market arrangements intended to alleviate these challenges. Specifically, we consider:

- Increasing the reliability margins on the interconnector;
- Holding some trade capacity back to be released intraday;
- Restricting the generator's participation in the trading and imbalance arrangements of its home market; and,
- Linking the trade and imbalance positions across multiple markets to take account of the congestion challenge.

Increasing reliability margins

Operationally, the simplest means to avoid the congestion problem described in the example above would be to maintain a larger reliability margin on the cross-zonal cable. This reliability margin could then be eaten into in the event that the offshore generator's injections were higher than anticipated.

However, this 'solution' has a significant economic cost, as it implies withdrawing the associated capacity from the market and thereby forgoing any value that could potentially be realised from using this capacity. Given this cost, reserving capacity permanently for this purpose seems unlikely to represent an appropriate solution.

Increasing reliability margins may also require revisions to the formal methodology used to calculate these margins. As set out in Section 3 of Regulation (EU) 2015/1222 on capacity allocation and congestion management, the relevant methodologies are established at the capacity calculation region. Consequently, altering these methodologies may be difficult in practice.

Holding capacity to intraday

A less costly option would be to hold some available cross-zonal capacity until closer to real time in the expectation that forecasting accuracy will improve over time (see Figure 2 above). In this way, the cross-zonal capacity that is reserved can still ultimately be used by the market, but the congestion risk is mitigated. Article 17(2) of Regulation (EU) 2019/943 states that "Transmission system operators shall propose an appropriate structure for the allocation of cross-zonal capacity across timeframes, including day-ahead, intraday and balancing." This suggests that such temporary reservations of capacity are compliant with existing regulation.

As set out below, this approach will not ultimately improve dispatch efficiency. The generator's actual output will be uncertain at the day-ahead stage regardless of whether or not capacity is reserved and the dispatch solution will therefore need to be updated through intraday trading to reflect changes in the forecast. Reserving capacity has the effect of changing the default starting position going into intraday trade, but does not alter the types of adjustment that will be required. However, reserving capacity does mitigate the potential need for countertrade and so can influence the distribution of revenues between the transmission owner and system operator where these are different.

Consider a case, similar to that pictured in Figure 3 above, in which the generator's output can take only one of two values: a lower and a higher volume of output (LOW GEN and HIGH GEN respectively). At the point at which cross-zonal capacities must be calculated for use in the day-ahead market, the generator's output is *expected* to take the lower value (LOW GEN), and thereby enable more cross-zonal flows. However, there is a chance that the generator will produce the higher output value (HIGH GEN) and leave less room than expected for cross-zonal flows.

The TSO can either provide the expected (higher) volume of available cross-zonal capacity to the day-ahead market (appropriate for LOW GEN), or else choose to provide only the lower volume that will be available under HIGH GEN, and then release any capacity that is subsequently remaining during intraday trade. This latter approach, in which some capacity is reserved for intraday trade, reflects the proposal under discussion.

The combination of possible outcomes associated with these different cases and strategies for the release of cross-zonal capacity are summarised in Table 2 below. The shaded outcomes are those in which the day-ahead solution ends up being correct, i.e., where, by good fortune, the volume of cross-zonal capacity released to the market day-ahead matches the volume actually available in real time. The key point to note here however is that, regardless of which approach is taken, there will be some cases in which the actual volumes don't equal those made available to the day-ahead market and then the dispatch solution needs to change. These outcomes are shown in the white cells.

Table 2: Example of Holding Cross-Zonal Capacity to Intraday

Case	Release Day-Ahead	Reserve to Intraday
LOW GEN	**Dispatch:** • Day-ahead solution is correct **Distribution:** • Transmission Owner gets congestion income for released capacity	**Dispatch:** • Market uses capacity released intraday to increase generation in foreign zone and decrease it in home market **Distribution:** • Transmission Owner initially forgoes congestion income and potentially recaptures it through an intraday auction
HIGH GEN	**Dispatch:** • System Operator countertrades intraday reducing generation in foreign zone and increasing it in home market **Distribution:** • Transmission Owner gets congestion income for released capacity day-ahead. System Operator must pay for countertrade intraday	**Dispatch:** • Day-ahead solution is correct **Distribution:** • Transmission Owner forgoes congestion income

If there is less cross-zonal capacity available when we move to the intraday timeframe, the system operator likely needs to conduct countertrade in the intraday market to 'correct' the dispatch solution. If there is more cross-zonal capacity available, then intraday trades using this capacity 'correct' the dispatch solution. These outcomes are effectively symmetrical with neither being inherently better from an efficiency perspective. However, if day-ahead forecasts are reasonably accurate, then the absolute scale of this 'corrective' redispatch during the intraday time-frame is likely to be smaller if we release the cross-zonal capacity to the day-ahead market in line with these forecasts, rather than reserving capacity to account for a less likely worst-case scenario.

There are some distributional consequences of the different approaches, although these will be limited where the transmission owner and system operator are the same entity. Under LOW GEN, the Transmission Owner will receive the congestion income associated with the available cross-zonal capacity provided this capacity is released via an auction and not though continuous trade. This anticipates the introduction of intraday auctions as part of the future European market design.

Under HIGH GEN, the generator's higher assumed real-time injections imply that there is no additional cross-zonal capacity available on which to earn a congestion income. Under the approach in which this cross-zonal capacity is erroneously released for trade at the day-ahead timeframe, the transmission owner will nevertheless earn congestion income on the capacity, even though this cannot subsequently be used. The system operator will subsequently need to conduct countertrade on the intraday market, effectively paying back this congestion income in order to recover the now unavailable cross-zonal capacity. Where the transmission owner and system operator are distinct parties, there will therefore be a systematic redistribution of income from the system operator to the relevant transmission owner.

Importantly, the systematic reservation of cross-zonal capacity until the intraday timeframe should not result in a distortion of market prices across these timeframes provided that there exist capable market participants able to arbitrage their positions across both the day-ahead and intraday markets. Withholding cross-zonal capacity from the day-ahead timeframe might, in the first instance, be thought to contribute to a wider price spread across the relevant border in the day-ahead market solution. However, provided this cross-zonal capacity is expected to be released to the market later in intraday trade, this spread can be expected to contract again. This change in prices from the day-ahead to the intraday timeframe creates a profitable trading opportunity that traders should exploit and, in doing so, counteract. Only if these markets are not well-functioning, such that traders cannot recognise and trade against the creation of any systematic price differences from the day-ahead to intraday timeframes, would the reservation of capacity for intraday trade distort the efficiency of the prices in these markets.

In conclusion therefore, reserving cross-zonal capacity is unlikely to contribute to dispatch efficiency. Corrections will be necessary at the intraday stage and these are possible regardless of the reservation of capacity. However, reservation does have distributional impacts, because the financial costs and benefits associated with decreasing and increasing available capacity during intraday trade fall on different parties. These distributional impacts could, conceivably, affect investment efficiency.[5] Reserving capacity for release during intraday auctions may be a reasonable way of ensuring the efficiency of investment incentives. Doing so helps to avoid a situation in which the transmission owner systematically benefits from capacity that is later unavailable at the expense of the system operator. Based on our limited review of the existing European regulation, such reservation appears to be possible already, subject to review by the appropriate regulatory authorities.[6]

Restricted participation in the Home Market

As was shown in the example discussed at the beginning of section 2.2.3, generators' actions in response to changes in their expected generation at the intraday stage will likely fail to recognise the transmission constraints involved and may, in fact, be

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[5] Specifically, cross-zonal capacity owners may end up being paid for capacity that cannot subsequently be used due to internal congestion created by offshore generation. This might create a perverse incentive to overinvest in this redundant cross-zonal capacity. In practice, such investment decisions are rarely taken on the basis of the commercial case alone.

[6] In this regard, the NRAs may wish to refer to ACER's Guidance Note 1/2018 on Transmission Capacity Hoarding. See: https://documents.acer-remit.eu/category/guidance-on-remit/

counterproductive. As depicted in Figure 3, the generator's actions in response to excess production will stimulate other generation in the home market to reduce their output. However, since the relevant import cable is already at full capacity, the system operator will end up having to reverse this turn-down response. One possible means of avoiding this effect would be to limit hybrid offshore generators' ability to participate in the home market after the closure of the day-ahead market, thereby mitigating such unhelpful market actions.

We conclude that restricting hybrid generators' ability to sell additional production intraday is unlikely to be a good idea, even if we can overcome the obvious challenge that it is discriminatory against these generators. However, it may be appropriate to restrict the extent to which offshore generators within hybrid projects can take advantage of imbalance netting as part of a balancing portfolio that includes both onshore and offshore parties within the home market.

Looking first at intraday trade, restricting hybrid offshore generators' ability to sell additional generation intraday closes off an important mechanism for these generators to signal to the market that they expect their output to be higher than originally forecast and implies that this excess generation will likely just be spilled into imbalance unless the generator is willing and able to self-curtail. This is clearly undesirable from an operational security perspective, as it gives the system operator less time and fewer opportunities to respond.

In contrast, restricting an offshore generator's ability to net imbalances as part of a balancing portfolio that includes onshore parties does not pose a risk to operational security and arguably ensures that the imbalance settlement process is more cost reflective. While such netting is reasonable when considering the need to maintain the system's energy balance within a copperplate balancing area, imbalances on the part of the offshore generator are very likely to require specific system operator intervention because of the expected high utilisation of the transmission assets linking the generator to the rest of the home market and the resultant risk of congestion. Given this transmission constraint, the offshore generator would ideally face an area-specific balancing price that reflected the costs of balancing in that area. However, because European regulation quite reasonably links the definition of bidding areas and imbalance settlement areas, excepting where bidding zones are subdivided into multiple control areas,[7] the imbalance settlement price is likely to be uniform across the home market. Allowing the offshore generator to net imbalances with onshore parties therefore risks enabling the offshore generator to avoid imbalance settlement charges to an extent that is disproportionate with the generator's role in triggering the need for redispatch. Restricting the generator's ability to net imbalances in this way may therefore be a reasonable means of attempting to create more cost-reflective settlement charges that incentivise more efficient balancing activity on behalf of the generator itself.

This latter point is an issue for design of the national imbalance settlement regime and needs to consider the various national mechanisms in place to incentivise generator balancing. We have not considered the implications for European regulation, but are unaware of any restrictions that would prevent national regulators from restricting imbalance netting as described above.

Linking generator's trade and imbalance positions across multiple markets

Ideally, an offshore generator's market actions could be set up to trigger directly the responses needed to manage the system, removing some of the burden placed on the system operator, notably to conduct countertrade intraday. However, while such a setup might be theoretically possible, it would demand the use of complicated and coordinated fixes across markets that are specifically intended to accommodate hybrid projects. The

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[7] See Article 54(2) of Regulation (EU) 2017/2195

challenge of developing such special mechanisms would seem disproportionate to the potential benefits and we therefore conclude that such an approach is unrealistic.

Looking again at the specific case discussed at the beginning of section 2.2.3 and depicted in Figure 3 above, the increased output from the generator ultimately needs to be sold into the low-price foreign zone due to the transmission capacity restriction between the offshore generator and the home market. As is discussed in section 2.3.3, this is effectively what would happen under Offshore Bidding Zone arrangements with market coupling. Making this happen via the market without formal price zone splitting would, however, necessitate a series of rather cumbersome workarounds.

For example, you might imagine that in situations like this one, in which the landing cable linking the generator to the home market has its capacity fully allocated in the day-ahead market, regulation could require that further intraday sales by the generator must be sold into the uncongested foreign market. This approach quickly meets with a number of problems.

First, this would mean that the generator would cease to get the home market price for these sales, eliminating at least part of the rationale for the Home Markets approach.

Second, this would also mean that the generator's imbalance and settlement position would be split among at least two markets and that its final position might need to be netted across these markets. In this example, the generator's metered injections would exceed its sales in the home market, but this excess generation would be matched by an apparent shortfall in the foreign zone, where it sold power but had no injections. Coordinating the generator's settlement position across these different markets would require specialised arrangements to deal for this eventuality.

Finally, we have so far only considered one specific case in which the hybrid project imports into the home market, the landing cable connecting the generator to the home market has its capacity fully allocated and the generator wants to sell power intraday. However, the supposed regulatory solution that acts to redirect the generator's trading activity has to handle all of the possible congestion and redispatch possibilities that might arise, effectively doing the work of the system operator. That would mean, for example, that in this specific case, intraday sales by the generator are placed in the foreign market, while any purchases of power, for example to reduce the generator's net sales, be placed in the home market. If the flows of the hybrid project went the other way, potentially all intraday trades could be resolved in the home market. Capturing all these possibilities, especially for more complicated asset setups, and ensuring that the right markets are accessed as part of continuous intraday trade, would be challenging.

Overall therefore, we conclude that the linking of generators' trade and imbalance positions across multiple markets as a means of mitigating the extent of redispatch required by the system operator implies a degree of regulatory and operational complexity and coordination that is both unrealistic in the near-term and unlikely to be adaptable to more complicated asset configurations in the future.

2.2.3 Revenue Distribution and the Efficiency of Investment

Although we include a brief summary of revenue distribution implications here, a more extensive discussion can be found in Section 2.3.4 in relation to the Offshore Bidding Zones model. The relative implications for revenue distribution under the Home Markets model are perhaps easiest to understand in contrast to those of the Offshore Bidding Zone model.

Put simply, the economic value of hybrid projects results from the combined use of the generation and transmission assets – an unconnected generation asset has no economic value. Within limits, the exact allocation of this aggregate value among the individual assets does not affect economic efficiency. However, it is important that, where hybrid projects are net beneficial, the developer of each asset receives a sufficient share of the hybrid project's total economic value to enable investment. Problems may arise under the Offshore Bidding Zones model because more of the hybrid project's total economic value is likely to be earned directly as congestion incomes and this revenue is harder to redistribute among all investors so as to enable investment. In contrast, the market solution under the Home Markets model tends to allocate more market revenue to the generator and this revenue is then easier to redistribute subsequently, for example through network charges.

The mechanics of these differences in revenue distribution are described in detail in Section 2.3.4. Most obviously however, transmission assets connecting the generator to the home market receive no market revenues under the Home markets model. This money partly ends up with generators and partly ends up with the owners of other transmission assets.

The direct revenue allocation under the Home Markets model need not be inherently efficient, but it is likely to be easier to redistribute among market participants so as to enable investments than under the Offshore Bidding Zones case. This is because regulation imposes limits on the use of congestion incomes.

As noted above, the market solution will provide no revenues to the transmission infrastructure within Home Market. However, as with other internal transmission infrastructure, this is not inherently a problem for the efficiency of investment, since this investment can be alternatively funded through connection charges and network tariffs. Some of these charges/tariffs might well fall on the offshore generator, which benefits from the use of these assets. The absence of any congestion income implies that this transmission asset would more naturally form part of the regulated asset base of a regulated transmission owner, than be developed as part of a merchant project.

Conversely, the Home Markets model may give rise to congestion incomes on uncongested transmission assets connecting the offshore hub to other bidding zones. In such cases, the price spread across the connection will overestimate the marginal economic benefit provided by these connections.

In general, where power is exported from the generator to the home market, the Home Markets model results in a distribution of revenue that is equivalent to that of an onshore project. The full economic value of both the generation asset and any transmission capacity it uses to access the home market is granted to the generator through energy market revenues. Network charging can then be used to make the generation developer internalise the project's network cost implications. The efficiency of investment will, in this case, depend on the efficiency of the investment signals provided by the network tariff and connection charging regime.

Where the offshore generation is effectively supplying the home market and the network charging arrangements pass appropriate network costs onto the generator, investment incentives for generation and the internal transmission capacity should be efficient under the Home Markets option. In this case, investment will also only be profitable where the combined investment in generation and transmission capacity is economically efficient.

Importantly however, where the offshore generation asset is supplying a market other than the home market, the value of the hybrid project may still end being captured as congestion incomes, which are comparatively hard to redistribute. As such, the use of the Home Markets model does not necessarily eliminate the possible challenge of redistributing market revenues so as to enable investment. It merely mitigates this challenge through a tendency to award greater revenues to generators, which are subsequently easier to redistribute among all the investors concerned.

2.3 Offshore Bidding Zone

2.3.1 Priority Access for Cross-Zonal Trade

Under the Offshore Bidding Zone approach, a separate bidding zone is created for the offshore generator(s) with its own wholesale price. The connections to neighbouring markets are therefore interconnectors and the offshore generator's injections and transmission flows are cross-zonal flows. As such, allocating offshore transmission assets' full transmission capacity for cross-zonal trade no longer implies the need to restrict the volume of offshore generators' injections. For this reason, amendments to the current regulatory arrangements to ensure that cross-zonal flows are not prioritised over (internal) offshore generator injections, as assumed under the Home Markets model, cease to be necessary to ensure dispatch efficiency.[8]

2.3.2 Cross-Zonal Capacity Calculation

Since offshore generators' injections and flows become a part of general cross-zonal flows under the Offshore Bidding Zones option, it is no longer necessary to limit the transmission capacity available to the market in order to accommodate offshore generators' flows. These flows are a part of the market clearing solution. As a result, current approaches for cross-zonal capacity management can be applied without the need for a separate consideration of the offshore generators' transmission requirements. In short, capacity calculation is not a practical challenge in this case.

2.3.3 Balancing and Redispatch

Like the Home Markets solution, the use of offshore bidding zones also gives rise to some practical challenges regarding balancing and redispatch. First, there is the question of how imbalances will be efficiently resolved for offshore bidding zones that might consist entirely of variable renewable generation capacity.[9] Second, there is the issue of what imbalance price should be applied to balancing responsible parties in an offshore zone.

On the first point, imbalances are likely to be commonplace in an offshore bidding zone in which there are large quantities of highly correlated variable generation, the output from which cannot be known ahead of real time. Technical solutions to resolve such imbalances within the zone, for example using curtailment or offshore energy storage, are of course technically feasible, but may be inefficient relative to making use of balancing services located in interconnected zones. Take, for example, the situation depicted in Figure 4 below. Here, similar to the case considered above in Figure 3, the offshore generator produces more power than expected. Note that, unlike the Home Markets option, this will not be a problem in the intraday timeframe, since intraday price coupling will now correctly account for the transmission limits on both transmission assets and facilitate only those trades that are physically possible. In this specific case, if the offshore generator sells additional power during intraday trade, this power will only be available to buyers able to receive the power. Assuming the leftmost interconnector is fully utilised following day-ahead trade, this would imply that the power could only be bought by buyers in the low-price foreign zone on the right (or buyers in the offshore bidding zone itself).

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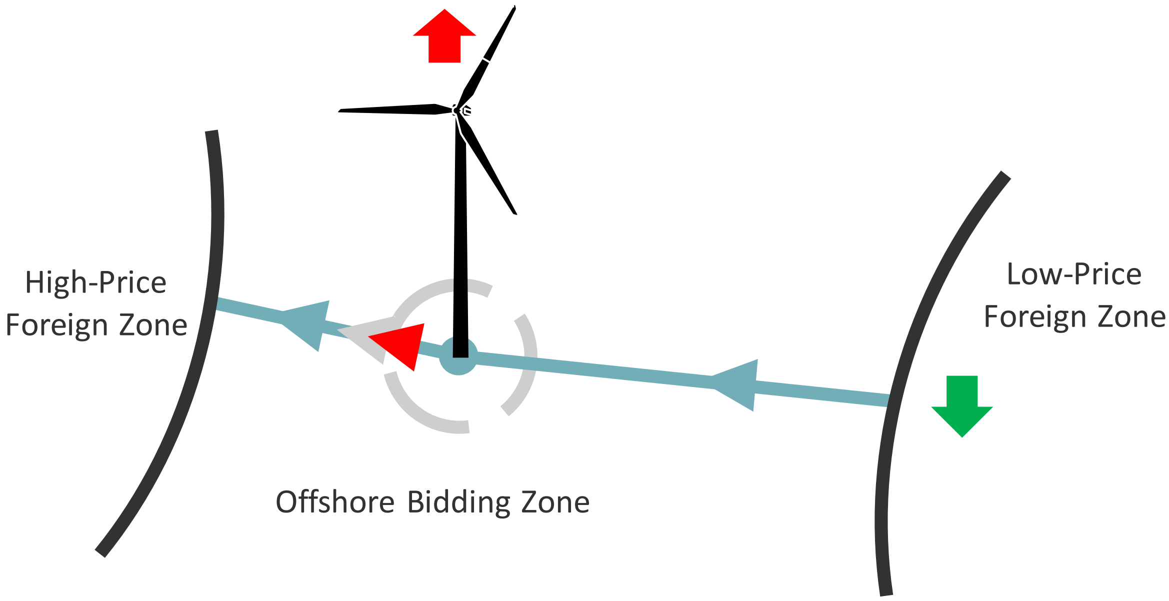
[8] See Section 2.2.1.

[9] Some offshore zones might include load. Load might potentially be located offshore, for example in the form of offshore hydrogen production, or at the landing site for the shore connection with the 'offshore' zone extended to include this landing zone.

Figure 4: Example of the Balancing Challenge under the Offshore Bidding Zones Option



If this additional generation is not accounted for as part of intraday trade, perhaps because it is not anticipated, the resultant balancing and congestion problems can be resolved using down regulation in the low-price foreign zone. However, this requires that the system operator for the offshore bidding zone is able to trigger the necessary balancing action in a separate onshore control zone. Note too that if the offshore generator had instead produced too little power, and the rightmost transmission cable were fully utilised, the appropriate balancing action would be to order upward regulation in the high-price foreign zone on the left. As such, efficient balancing may require the system operator to be able to trigger balancing actions in all of the connected onshore zones. Coupled balancing markets, as described below, should support this process.

On the question of the imbalance price, European regulation (Article 54(2) of Regulation (EU) 2017/2195) requires that imbalance price areas be no larger than a bidding zone. This implies that any offshore price zone will constitute its own imbalance price area. Given the potential interactions with balancing actions in different zones, this raises the question of how to establish an efficient and robust imbalance price for the offshore bidding zone itself.

Coupled balancing markets

Importantly, the challenge of balancing the offshore system is the same under either option for the definition of bidding zones and results from the physical limitations of the transmission system rather than the definition of bidding zones under the market arrangements.

At least part of the answer to ensuring that offshore bidding zones can be balanced with the help of actions taken in adjacent interconnected zones is likely to lie in the continued development of cross-zonal markets for balancing services. TSO-TSO exchanges of balancing services are already provided for by the Electricity Balancing Guideline and markets are already being developed through projects like Picasso.[10]

Especially in the near-term however, these market solutions may not include the full range of balancing services required or else exclude significant sources of balancing services available within adjacent markets. Consequently, close cooperation between system operators in the offshore bidding zone and those of connected zones, beyond that

[10] https://www.entsoe.eu/network_codes/eb/picasso/

enabled through cross-zonal balancing markets, is likely to be beneficial as a means of enabling access to these services and providers. One might be tempted to conclude that the Home Markets option is more likely to facilitate such coordination, since a single 'home market' TSO could hold system operator responsibility for both the offshore and home market system. Ultimately however, there is nothing inherent in the use of offshore bidding zones that precludes the use of a common system operator for the onshore and offshore zones. We return to this issue when we discuss governance arrangements in Section 5.

Imbalance pricing

Target European market design for imbalance pricing is based on the use of a single imbalance price.[11] Economic theory on the efficiency of imbalance pricing signals implies that this single price should reflect the marginal costs associated with resolving the system imbalance. The regulatory and theoretical principles that underpin the appropriate imbalance pricing for any offshore bidding zone are therefore already well established. The remaining challenge is therefore procedural, namely specifying the means by which the marginal cost of balancing actions can be calculated even where these actions are likely to take place outside the relevant zone.

Where the connected balancing areas themselves apply single marginal imbalance pricing and the offshore imbalance is resolved using balancing actions in these areas, the marginal prices can be used directly to estimate the marginal costs of balancing in the offshore zone. As a result, estimating the relevant marginal imbalance cost should be fairly simple even when relying on out-of-zone balancing. Where the connected zones do not apply single marginal imbalance pricing, more complicated arrangements may be needed to estimate the marginal costs of balancing. In either event, this is not a fundamental challenge to the use of offshore bidding zones and it should be possible to identify a suitable procedural solution even for problem cases.

2.3.4 Revenue Distribution and the Efficiency of Investment

The Offshore Bidding Zones approach imposes a distinct allocation of revenues among the different transmission and generation elements of the hybrid project. Where structural congestion occurs between offshore generators and a high-price home market, the generator will receive lower revenues relative to the Home Market solution, while transmission owners receive greater revenues in the form of congestion income. The extent to which this redistribution of income occurs depends heavily on the volume of transmission capacity to various markets, the configuration of offshore assets and the resultant location of structural congestion. We discuss these interactions in detail in Section 3.2.2.

European regulation places limits on how congestion income can be used and likely restricts transmission owners' ability to redistribute this income among the various investors involved. Unbundling regulation also prevents a single investor/owner from owning the hybrid project as a whole. The result of these restrictions is that, for a given hybrid project configuration, investors may be unable to share project revenues in such a way that all parties recover their cost. Consequently, there is a risk that it may not be possible to attract investment in economically beneficial and otherwise commercially viable hybrid projects.

It is important to note at the outset that TSO investment decisions may be taken for non-commercial reasons and TSOs may invest in projects that are not expected to recover their costs. Similarly, private investment in offshore generation capacity is currently realised through public support mechanisms and these support mechanisms could be used to ensure that investors in generation capacity are willing to invest under either bidding zone option. For example, many countries already support investment in offshore generation through Contract for Difference arrangements that effectively provide

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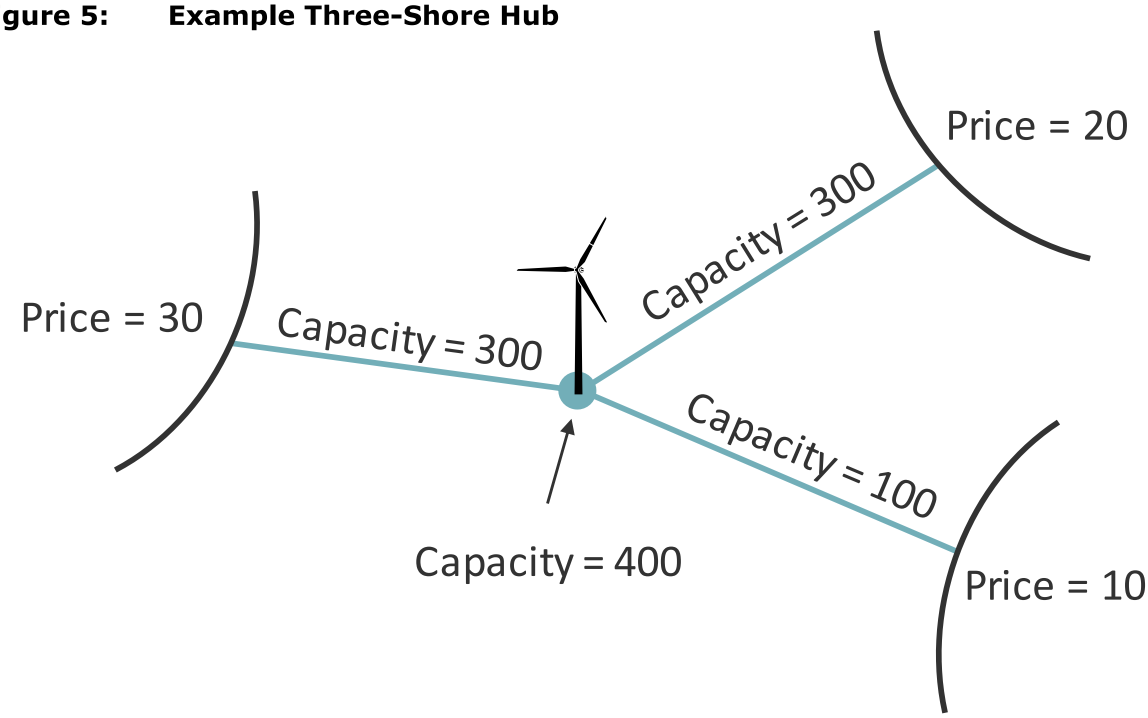
[11] See Article 7 of the [All TSO Proposal for Imbalance Settlement Harmonisation]

generators with a guaranteed wholesale price. Such arrangements, which reflect a proven development model and are compatible with state-aid guidelines, could be used to ensure that the revenues received by generators under the Offshore Bidding Zones model are sufficient to stimulate investment.

However, in the longer term, if the market arrangements are to facilitate the large-scale deployment of hybrid projects and be fit for a future energy system in which such projects are profitable on purely commercial terms, it seems reasonable that the market arrangements should, at a minimum, ensure that economically beneficial hybrid projects can, in theory at least, successfully attract private investment without public subsidy. At a minimum therefore, where the value of the hybrid project exceeds its costs, it should be possible for all investors to receive revenues that exceed their costs. The current market arrangements may prevent investors from dividing the financial returns among themselves in such a way that each investor can recover their investment costs, even where the commercial returns to the hybrid project are sufficient to do so.[12]

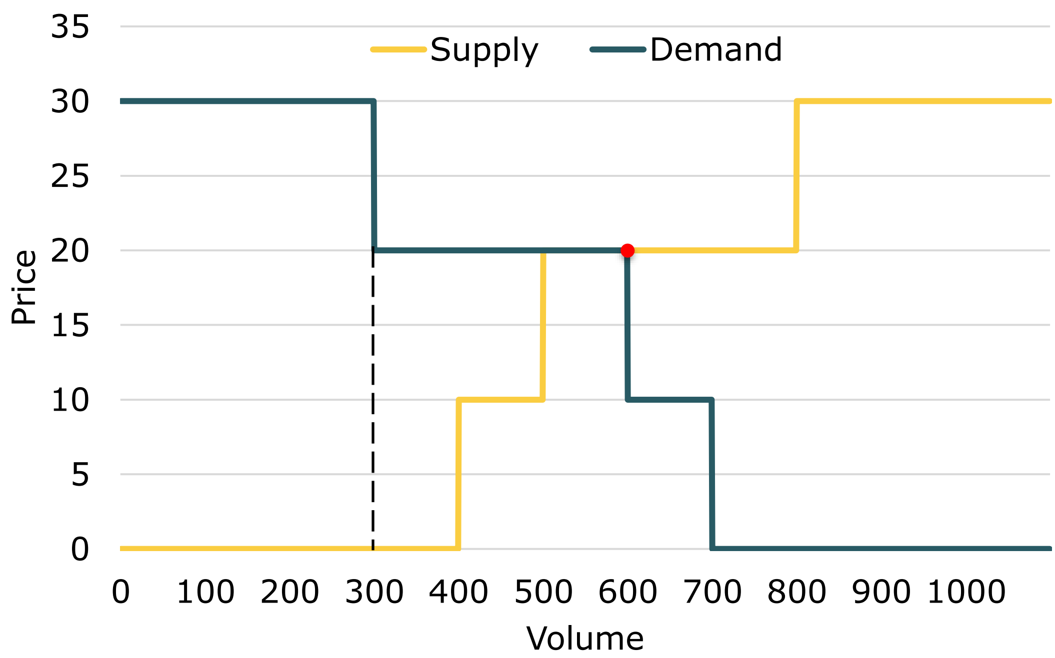
To understand why this is the case, we first need to understand the price dynamics and implied revenue allocation associated with the Offshore Bidding Zones option. Under this option, offshore generators can receive a distinct price and this price is intended to support more efficient dispatch. The price for the offshore bidding zone is set by the intersection of supply and demand in the relevant zone and some of this supply and demand for power is effectively imported via the interconnectors. A reasonable intuition for pricing dynamics can be gained by looking at the case depicted in Figures 4 and 5 below.

Figure 5: Example Three-Shore Hub



[12] It is worth noting that transmission and generation owners may be able to indirectly redistribute incomes among themselves by changing the dimensions of the relevant generation and transmission assets. Altering the size of transmission assets can shift the location of congestion and alter the distribution of generation and transmission revenues. This could, theoretically at least, distort dimensioning decisions relative to a case in which these decisions were based solely on maximising welfare.

Figure 6: Example of Price Determination in an Offshore Bidding Zone



In this case, we have an offshore wind hub that is its own offshore bidding zone linked to three separate onshore price zones. Figure 6 shows what the supply and demand curves for power look like as viewed at the hub, assuming that the wind power is offered at zero marginal cost. The dark blue line shows effective demand. At the top left of this line, we see a willingness to pay of 30. This reflects the 'imported' demand from the left-most zone. The yellow line shows supply. At the bottom left of this line, we see power being offered at 0 price. This is the wind power supplied at the hub. Now imagine moving from left to right across this figure, trying to match supply and demand at the hub. After the first 300 units of demand are met, the interconnector supplying the high-price zone becomes congested. Further demand for power at the hub now comes from the next-highest-priced zone at a price of 20. After a total of 400 units are supplied, the wind capacity is fully utilised. Further supplies must now be sourced from the next cheapest source, namely imports from the low-priced zone on the bottom right. We continue to move to the right until we reach the point marked by the red dot. This would be the market-clearing solution in this case under the current market arrangements. If we attempt to move any further to the right, the costs of supply exceed the willingness-to-pay of demand and we would be inducing inefficient dispatch.

At the clearing solution, we have fully utilised the transmission capacity available to the highest-priced zone and from the lowest-priced zone. However, transmission capacity to the zone with a price of 20 is only partially used (net exports of 200 out of a capacity of 300). In general, the price in the offshore bidding zone will split from that of any connected zone where the transmission capacity limit between the zones is binding (i.e. where it actively constrains trade) and will equal the price of zones where the available transmission capacity is not fully utilised.

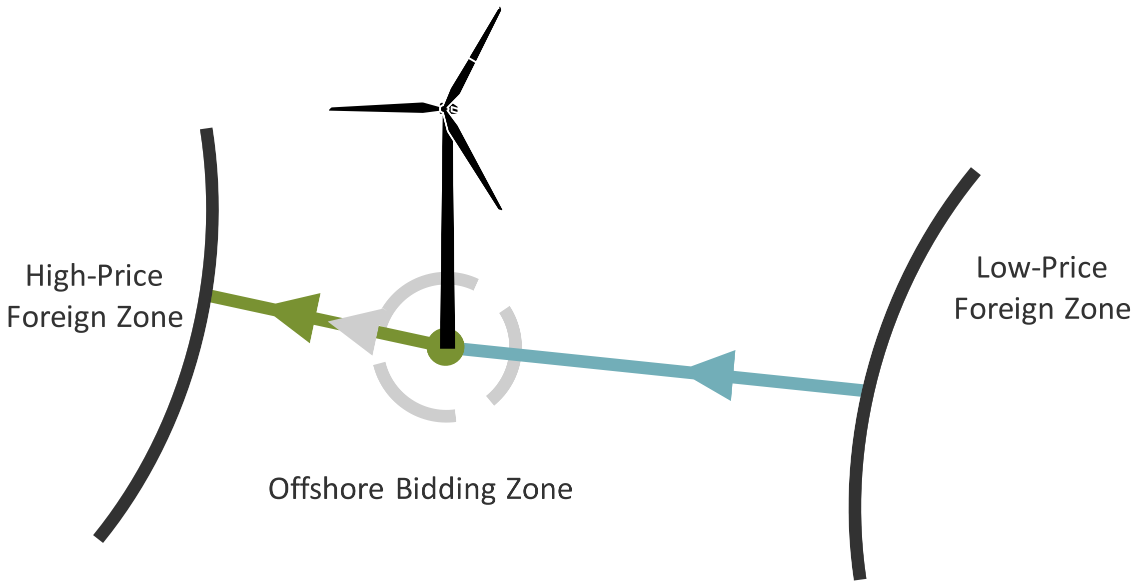
The key insight from this example is that, although the offshore wind generator here can be reasonably said to supply power demand in the high-priced onshore market, it is unlikely to receive this high price for its power. This is because the available transmission capacity from the offshore bidding zone to this high-priced zone is, in a sense, used up first, likely to become congested and therefore likely to result in the offshore bidding zone price splitting from that of the high-price market to equal that of a lower-priced market.[13] The exact result will, of course, depend on the specifics of the case. If the sum

[13] Note that this can also happen under the Home Markets option where the offshore generator is routinely exporting to a market other than its home market.

of wind generation and all transmission capacity to lower-priced zones is less than the transfer capacity to the high-priced market, congestion will instead occur on the interconnectors importing power to the hub and the generator will get the high price. For plausible hybrid project setups, however, congestion is likely to occur at least some of the time between the offshore price zone and onshore zones with higher prices. This will imply that the offshore hub receives a lower price than that in the high-price zone to which the wind power is exported.[14]

It is also worth noting that this tendency for the offshore hub to receive lower prices is robust even where the zone with the higher price changes. Take for example the case depicted in Figure 7 below and assume that the transmission capacities on both the green and teal interconnectors are equal. In this case, if the offshore generation wishes to get dispatched, it will need to accept a price equal to that of exports from the low-price zone. This is true regardless of which zone has the lower price. Let us imagine that the price spread between the two onshore zones reverses, such that each zone is the lower-priced zone half of the time. The direction of flows will reverse as needed to flow power from the low- to the high-price zone, but, in this specific setup, where the generator sits on a symmetrical interconnector, the offshore wind farm must *always* accept the lower price if it is to be dispatched, irrespective of where this price occurs. Under the Home Markets arrangement, the generator could at least expect its home market to have a higher price some of the time and, as a result, the generator is made strictly worse off by being in its own bidding zone.

Figure 7: Example of Price Dynamics on an Interconnector Tie-In Project



The implied reduction in generator revenues resulting from the Offshore Bidding Zones arrangement is not lost in an economic sense but rather transferred to the transmission asset owners in the form of congestion income. Indeed, what is happening here is that the economic value provided by the hybrid project is being redistributed among the various parties involved. Anything lost by the generator is gained by the transmission owner and vice versa.

From a strictly economic perspective, the reallocation of revenues is not inherently good or bad, and pricing behaviour under the Offshore Bidding Zones option is fully efficient

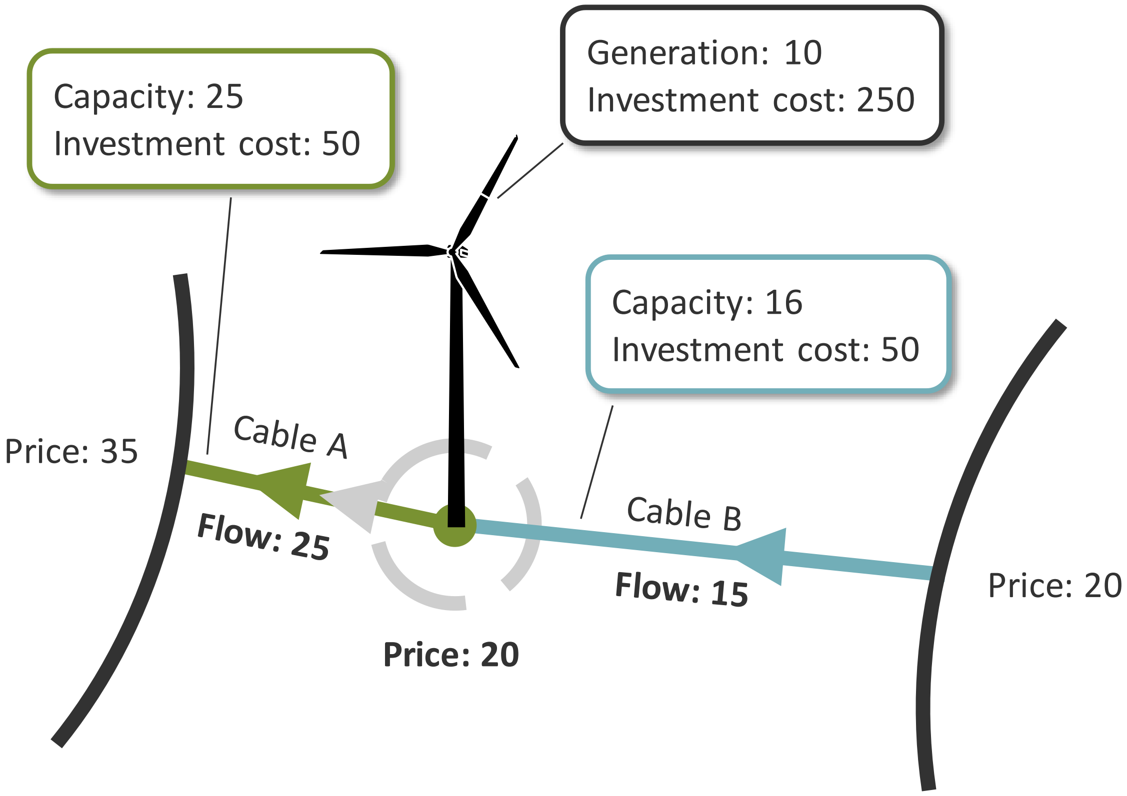
[14] Note that this result is not unique to offshore hybrid projects. A wind generator in Northern Sweden (a generally low-price exporting bidding zone) will typically receive a lower price for the power it produces than the economic value of that power as viewed by its ultimate consumer. In both cases however, the price the generator receives will accurately reflect the marginal value of changes in generation in the bidding zone, given transmission constraints. What makes the hybrid projects case different, as we discuss below, is that we need to consider how to divide the aggregate economic value of a combined generation and transmission investment among the different investors involved.

since the price received by the offshore generator always reflects the true marginal value of the power supplied. In the example above, the offshore generator's power always ends up displacing power from the lower priced zone and so marginal decisions about generation or consumption offshore should be made with respect to this price. This supports the overall efficiency of dispatch (as discussed in section 4.2.1) and the efficiency of marginal investment decisions.

However, as we show below, when the distributional dynamics of the Offshore Bidding Zones approach are combined with the current restrictions on the use of congestion income currently in EU regulation, it may not be possible for investors to organise commercial investment arrangements even for hybrid projects that are otherwise economically beneficial and commercially profitable.

The crux of the problem is that even where a hybrid project generates enough value to cover its costs, restrictions placed on the use of congestion income earned by interconnector assets may prevent these revenues from being redistributed in such a way that all investors receive a return. Figure 8 below illustrates this problem.

Figure 8: Example of the Investment Challenge



This example shows a specific set of flows and prices for the relevant markets consistent with current market practice, but in which the generator is located in an offshore bidding zone. For reasons of simplicity, let us assume that this situation is reflective of expected conditions over the lifetimes of the assets involved and, therefore, of the revenues that the investors can expect to receive if they invest. These revenues and the difference relative to the costs of investment are shown in Table 3 below.

Table 3: Example Revenues and Investment Costs

Asset	Price	x	Volume	=	Revenue	Investment cost	Difference
Cable A	(35-20)		25		375	50	325
Cable B	(20-20)		15		0	50	-50
Generator	20		10		200	250	-50

Importantly, the numbers shown are not based on real numbers, and the results of the modelling work show that generator revenues are often only slightly reduced or else remain unchanged under the Offshore Bidding Zones setup as compared to the Home Markets setup (see Section 3.2.1). However, while the magnitudes may be meaningless, this numerical example does serve to demonstrate some key insights. First, even in the absence of this example, it should be clear that none of the individual investments provides any economic value in isolation. A stranded offshore windfarm and a transmission cable that simply leads to a dead-end in the sea serve no economic purpose. However, in combination, these assets do provide value. Given the numbers assumed, the hybrid project as a whole is net beneficial. The value it provides is reflected in the sum of the revenues received (575) and exceeds the assumed total costs of investment (350). The project should, therefore, be viable on fully commercial terms.

Under the market arrangements, the revenues generated by the project will be allocated as shown in Table 3. A significant share of this revenue accrues to the congested transmission asset (Cable A) since price splitting occurs across this asset and the cable, therefore, receives a congestion income. Conversely, no revenue accrues to the uncongested transmission asset (Cable B), since its capacity is not scarce, and prices are the same across the cable. Note that this occurs even though Cable B's capacity is being partially used and is essential to realising the flows that provide the bulk of Cable A's revenues. The generator earns revenues for the power it sells. All of this power is used to supply demand in the high-price zone, but as noted previously, the power price in the offshore price zone, which determines the generator's revenues, is the lower price (20).

Unfortunately, given this assumed distribution of revenues, both Cable B and the generator fail to make up the costs of their investments. Fairly obviously, with no congestion income, Cable B is not commercially viable even though, as previously mentioned, it is contributing to the overall value of the hybrid project. In this case, the offshore generator's revenues are also insufficient to cover its costs.[15]

This need not necessarily be a problem, provided that the relevant investors can find a mechanism to redistribute their aggregate revenues. Cable A's investor cannot realise these revenues independently and, as such, should be willing to share its revenues with the other investors if doing so encourages them to invest. It may well be able to do so for Cable B, potentially by incorporating both cables into the same joint project.

Unfortunately, barriers, both regulatory and practical, act to ensure that no such revenue-sharing agreement is possible between the transmission and generation asset

[15] It should be noted that the same distributional problem could also exist under the Home Markets arrangements were the offshore generator to be located in the low-price zone despite effectively supplying the high-price market. Again, the generator's direct revenues may fail to signal the true economic value of the project.

investors and, consequently, projects like this one could not be developed on commercial terms.[16]

The most obvious barrier is Article 19 of Regulation (EU) 2019/943. This Article effectively requires that all congestion income be earmarked for securing or expanding cross-zonal capacity. If these objectives are adequately fulfilled, congestion incomes may alternatively be returned to network users through lower tariffs. These restrictions on the use of congestion income appear to limit the transmission owner's ability to redistribute congestion income to other investors, notably those responsible for investment in generation capacity, even where this is required to ensure the project's viability.

It should be noted that an exemption route to these requirements already exists under Article 63, which enables a time-limited exemption for new merchant interconnectors that can be provided on a case-by-case basis. However, this exemption route does not appear to anticipate its use for hybrid projects and, given its case-by-case nature, imposes a degree of regulatory risk that is likely to discourage investors. It is also explicitly unavailable to interconnection projects owned by system operators or to existing interconnectors unless they undergo significant capacity increases.

It has also been suggested that the restrictions imposed by Article 19 could potentially be avoided if National Regulatory Authorities instructed TSOs to pay generators using funds raised through network tariffs, essentially setting up a parallel and offsetting cashflow. In this case, the TSO would earn congestion incomes and distribute these to network users (as allowed under Article 19) but, in parallel, raise funds from network users and distribute them to generators. The legality of such a workaround proposal is unclear and may cause additional legal implementation challenges at a national level.

Even were these regulatory restrictions and risks to be removed or avoided, it should also be recognised that a practical challenge remains for the investors involved associated with developing contractual arrangements that share the revenues and risks associated with a hybrid project in a way that is acceptable to all parties. For early hybrid projects operating under an Offshore Bidding Zones option, a time-consuming and potentially costly series of commercial negotiations is likely to be needed to figure out how to share revenues and risks. Since the projects are also likely to receive public support, these negotiations may also need to involve the relevant national policy leads. As such, while a commercial solution may well be feasible given suitable regulatory reforms, realising it still represents a significant coordination challenge for the industry.

If it is determined that this distribution challenge should be addressed, we can imagine three potential approaches to do so:

1. Allow for the redistribution of congestion income within hybrid projects (Redistribution Approach) – This would remove the key regulatory barrier and likely give National Regulatory Authorities the flexibility to establish redistribution mechanisms consistent with certain principles.

2. Allocate the 'congestion income' directly to the generator (Allocation Approach) – This would potentially entail the creation of a new regulatory definition for hybrid projects that explicitly recognises a subset of cross-zonal flows as producing congestion incomes that belong to offshore generators.

[16] Such projects could still be developed using support schemes for the generator. One might imagine, for example, that the congestion incomes on the cable are returned to grid users through lower tariffs, but that these users pay additional charges that are used to make support payments to the generator. This indirect means of revenue redistribution may have undesirable side effects, since the generator appears to be subsidised, even though it is really having economic value that it creates recycled back to it through a support scheme. The general desire to reduce public subsidy and lower consumer costs may therefore limit the extent to which such redistribution is possible and could result in these redistribution flows being counted against funds promised for the support of renewable generation. These issues limit the extent to which support schemes represent a fix to the distributional challenge described. It is also undesirable for the market arrangements to be reliant on support mechanisms to enable commercially and economically efficient investments, given the scope for these mechanisms to vary across countries and over time.

3. Enable the joint ownership of generation and transmission assets where they form a hybrid project (Joint Ownership Approach) – This would enable generation and transmission developers to develop such projects as joint ventures that can consider project costs and potential revenues in aggregate.

We discuss these different approaches further in the three subsections below and consider their relative merits against our key assessment criteria.[17] We devote the most space to the Redistribution Approach as this approach has several sub-options for detailed implementation that are already under consideration by the industry and many of the arguments raised here apply to the other approaches as well.

Redistribution Approach

Under the Redistribution Approach, the offshore generator receives a share of the congestion income according to a set of contracts or financial instruments intended to redistribute this income from the transmission owner to the generator. We consider three options for achieving this:

1. Contracts for Difference between the transmission owner and the generator. Here the transmission owner and the generator effectively agree to transfer the price spread between the offshore and onshore bidding zones for the actual volume of power supplied by the generator. This is equivalent to having the transmission owner pay the generator the congestion income earned on its generation.

2. Allocating Financial Transmission Rights to the generator. This allocation may or may not imply the need for some payment from the generator to the transmission owner. The FTRs can have different features, e.g. be directional or non-directional, obligations or options. The FTRs can be traded in the secondary market.

3. Allocating Auction Revenue Rights (ARRs) to the generator. The transmission owner sells FTRs in an auction and a share of the auction revenue is allocated to the generator in the form of ARRs.

All of these options involve transferring an uncertain cashflow that reflects the value of transmission ownership from the transmission owner to the generator. In effect, they provide the generation owner with a sort of virtual transmission asset that can help ensure that the generator's aggregate revenue stream is more similar to that of a project with a direct-to-shore connection. In exchange, the generator might potentially be asked to contribute to the cost of the physical transmission capacity that underpins this virtual asset.

The Redistribution Approach could be set up to simulate a direct-to-shore connection and, potentially, allow hybrid projects to compete on similar terms to projects with direct-to-shore connections within existing support schemes. Under such an arrangement, the offshore generator would effectively receive the price of a given onshore zone, as a result of the redistribution of congestion incomes, but be required to pay (network) charges that mimic those of a direct-to-shore connection.

More generally, the Redistribution Approach could be used in conjunction with a support scheme to help ensure that higher subsidies are not required for projects in offshore bidding zones. This would help to ensure both that different project types and different project setups compete for support on an equivalent basis, where relevant, and that the required subsidy is as small possible, hopefully allowing for zero-subsidy or fully commercial setups as soon as possible.

[17] As set out in detail in section 4.1.

Dispatch

With respect to dispatch, the main factor to consider is whether these options create incentives for the generator to bid strategically.

With Contracts for Difference, the generator will always effectively receive the onshore price in aggregate independent of the actual offshore price when generating. As such, there are no incentives for strategic bidding on the part of the generator provided that the contract covers all of the generator's output.

FTRs also effectively provide the generator with the associated onshore price and therefore should also remove incentives for strategic behaviour on the part of the generator.[18] There is a risk that the volume of FTRs does not match the generator's actual volume of generation, in which case some residual incentives for price manipulation may remain. However, this is not expected to represent a serious risk.

With ARRs the payment received by the generator is distinct from the realised congestion income and, in the short-term, effectively acts as fixed extra income for the generator. This implies that the generator is still exposed to price changes in the offshore bidding zone and means that the generator still has an incentive to bid strategically. In the long term, however, and with repeated auctions, the price received for the FTRs and hence the ARR payment to the generator will depend on the expected offshore zonal price, which is itself dependent on the expected behaviour of the generator. If the generator inflates the offshore price, this will tend to reduce the expected auction revenues. As such, manipulation will not be a viable long-term strategy where participants in the FTR auction come to anticipate the effect of the generator's strategic behaviour.

Investment

All three options can be used to redistribute congestion income to the generator in support of investment. While all of the options can be designed to yield the necessary expected level of revenue to ensure that an offshore wind generator investment is profitable, the risk characteristics differ. Specifically, the three options allocate price and volume risk differently between network users and generators. The key differences are summarised in Table 4 below.

[18] If the generator decides to sell the FTRs in the secondary market, the incentive to bid strategically to increase the offshore bidding zone price would return. However, the price received for the FTRs will depend on the prospective buyers' expectations of the generator's behaviour and the resulting zonal price, which should partly offset the ability of the generator to benefit from a strategy of selling the FTRs and then manipulating the offshore price.

Table 4: Quality of Price and Volume Hedge for Generator Under Alternative Revenue Sharing Arrangements

	Price	Volume
Contract for Difference	✓	✓
Financial Transmission Right	✓	✗
Auction Revenue Rights	✗	✗

Contracts for Difference allow the generator to effectively earn revenues as though it were directly connected to the relevant onshore market. FTRs have a very similar effect, but there may be some difference in the volume of flows covered by the FTRs and the generator's actual generation. This difference means that there is some additional risk held by the generator, relative to the Contracts for Difference case, but this is not expected to materially alter investability.

The ARRs again are notably different from the other two options in that auction revenues will not reflect the actual price spread and, as a result, the generator remains exposed to short-term price risk. Although this might be thought to discourage investment, it should be remembered that the generator can also participate in the FTR auction and effectively turn its ARRs into FTRs, thereby regaining a price hedge. As such, there may be little difference between the options' hedging implications in practice.

Assuming that realised congestion incomes will tend to be higher than auction revenues[19] or the value of FTRs in the secondary market, Contracts for Difference will tend to yield slightly higher revenues to the generator than the FTR or auction-based mechanisms.

For the offshore network owner, the impact on investability will depend on whether a TSO or an OFTO is responsible for transmission investments offshore.

For the TSO, there is no impact from any of the models assuming that the offshore network assets are included in the regulatory asset base and any shortfall from congestion income transferred to the generator can be offset against tariffs. The TSO's investment incentives then depend on the general investment incentives in the economic regulation of the TSO, i.e. whether the expected rate of return is greater than the TSO's cost of capital. The regulatory WACC is an important element in that assessment.

For an OFTO, their income will consist of congestion income and any tariffs or connection charges paid by the offshore network customers. The OFTO's investment incentives will depend on the regulated payments from the generator towards offshore network costs

[19] Earlier unpublished analysis by THEMA comparing historic transmission capacity auction prices with their associated congestion income suggests that auction prices may, on average, clear slightly below the value of the associated congestion income.

(including any costs that may arise from strengthening the onshore network that are charged to the OFTO). If the generator pays these network costs (total costs, not just the connection charge), the OFTO should be able to invest even if congestion income does not end up with the OFTO as a result of these redistribution mechanisms. However, the different options alter the revenue risks held by the OFTO and may influence the investment case. Note that the OFTO results also apply in principle to a TSO who is not allowed to fully offset variations in congestion income against tariffs.

Subsequent investments in P2X or additional generation capacity at the hub are not expected to be significantly impacted by the choice of redistribution option, as there should not be any impact on pricing at the hub. There may be some indirect effects associated with changes in FTR liquidity and therefore in hedging costs. Specifically, the FTR and ARR options require the transmission owner to allocate or auction a certain volume of FTRs. Under the FTR model these are handed to the generator and so would not contribute directly to market liquidity. Under the ARR approach, these volumes would necessarily be available to all market participants at auction, making third-party hedging easier.

Regulatory compliance

As noted previously, all these options may be incompatible with Article 19 of EU Regulation 2019/943. The FTR option is also likely to conflict with Articles 31 and 50 of EU Regulation 2016/1719 and with Article 9 of EU Regulation 2019/943, which govern the non-discriminatory auctioning of FTRs using the Single Allocation Platform. As such, the direct provision of FTRs is likely to be the most problematic option from a regulatory perspective.

Cross-zonal hedging

The redistribution mechanisms have different properties with respect to cross-zonal hedging as summarised previously in Table 4. In all cases, risks are redistributed between generators and network users. Specifically:

- Using Contracts for Difference, the generator achieves a perfect hedge. The mechanism provides a hedge for both prices and volumes and the generator is effectively guaranteed the onshore price by the transmission owner. In practice, the transmission owner reimburses the generator for any shortfalls and receives a payment if the offshore price exceeds that of the onshore price when the generator is generating.
- Under the FTR mechanism, the price will be hedged as above, but the actual generation may deviate from the volume of the FTRs allocated to the generator.
- Under the ARR option there is no direct link between the payment to the generator and the actual market prices and volumes generated. However, over the longer term, auction revenues should be correlated with changes in congestion incomes and the value of FTRs.

Again, sufficient FTR volumes must be made available to cover the needs of the redistribution mechanism under the FTR and ARR options.

Political acceptability

Regarding the options' ability to support diverse national regulatory models and support schemes, and to facilitate flexibility in the distribution of costs, we note the following:

- Assuming TSO investment, national TSO regulation must allow congestion income to be offset against tariffs. This is necessary to ensure that the TSO does not bear risks related to congestion income, which could otherwise negatively affect the TSO's incentives to invest in the offshore network, particularly if the offshore wind generator and other offshore network users do not pay the full costs of the offshore network. Not all countries in the North Sea region currently allow congestion income to be offset against tariffs.

- More generally, TSOs' financial performance needs to be isolated from any power-price-dependent payments or revenues under all of these models to ensure that the TSO does not have any incentive to influence the power price. Again, for example, it is important that TSOs do not benefit financially from higher congestion income, since this would create an incentive to operate the system so as to maximise this income, potentially to the detriment of European welfare. The current restrictions on congestion income require that any income that is not invested or used to maintain interconnector capacity is returned to network users, thereby ensuring that the TSO itself is financially indifferent, and these restrictions exist, in part, to prevent congestion incomes giving rise to inappropriate TSO incentives. Assuming TSO investment in the transmission infrastructure, all of the options entail the TSO giving a part of the realised congestion income to the offshore wind generator. Like the congestion income itself, these payments will depend on realised power prices. The extent to which existing national regulation will isolate TSO financial performance from these payments differs by country and option. In particular, the CfD contracts do not currently exist and so existing national regulations are unlikely to already allow for these payments to be passed directly to network users. The ARR and FTR options build on existing arrangements that are directly linked to congestion income and may, as such, be easier to offset against tariffs as part of existing regulations.
- The options could, in principle, be combined with a variety of support systems in use for offshore wind generators today but would likely add to the complexity of making bids as part of support scheme auctions. Where bilateral contracting is used, the terms of these contracts would probably have to largely be stipulated as part of any tendering process, which may be challenging, especially for early tenders.

Scalability and adaptability

The FTR option is expected to be the least difficult to scale up and adapt to a large set of hybrid projects, as it builds on an existing set of instruments. However, it must be noted that the FTR arrangements would, in principle, have to cover the entire lifetime of the offshore wind generator, typically a 20–25-year period. While the instrument is not new, providing FTRs over such a long period would be unprecedented and therefore come with significant long-term market and regulatory risks. Dealing with these risks may imply the need for NRA involvement and, potentially, negotiations among the stakeholders involved. As such, the challenges associated with scaling and adapting the FTR option are not trivial.

We also expect the ARR option to be fairly easy to standardise eventually, although such contracts have yet to be used in the European power market context. Again, ARRs will need to be allocated over a long period of time and doing so is not trivial.

The Contracts for Difference option is potentially the most difficult to scale as it relies on the creation of tailored agreements between transmission owners and generators that likely need to be overseen by NRAs and possibly other member states. Where these agreements are the result of multilateral negotiations, the complexity of this negotiation process could act as a barrier to scalability. However, such contracts could also become increasingly standardised over time. Where the intention is to use such contracts in conjunction with a tendering process, the key terms of the contracts could be pre-defined as part of a tendering process, with some variables potentially forming a part of generator's bids.

Allocation Approach

This approach would require the creation of a new regulatory definition for hybrid projects that defines a subset of cross-zonal flows as generating congestion income belonging directly to offshore generators.

Dispatch

If the congestion income allocated to the generator is dependent on the generator actually generating, the incentives will be identical to those under the Contracts for Difference approach.

Investment

The investment incentives for the generator are similar to when congestion incomes are redistributed as discussed above. However, assuming that realised congestion incomes tend to be higher than auction revenues, as noted in the discussion of the Redistribution Approach above, the direct allocation of congestion income will tend to yield slightly higher revenues for the generator than the use of ARRs. There may also be differences in generators' perceptions of regulatory risk that influence the attractiveness of investment. For example, if the Allocation Approach were only accessible through the use of a case-by-case regulatory exemption, this might expose hybrid projects relying on such exemptions to comparatively high regulatory risk and make them less attractive than alternative investments.

Another challenge is the fact that the congestion income distribution will potentially need to be negotiated between many stakeholders. At least two TSOs are likely to be involved in the case of hybrid assets, and many offshore wind generators may want to build in the same area, creating a need for complex multilateral negotiations if many offshore wind generators invest at the same time, or renegotiations over time as more offshore wind generator projects emerge.

Transmission investment incentives under the Allocation Approach match those under the Redistribution Approach.

The stability and predictability of the investment environment under the Allocation Approach will be largely dependent on the expected resilience of the Allocation Approach to the regulatory challenges discussed below.

Regulatory compliance

The Allocation Approach implies the need for more significant regulatory development than the Redistribution Approach discussed previously. Rather than just exempting hybrid projects from the restrictions on the use of congestion income, the revised regulation would need to define both the projects that are eligible, potentially through the creation of an authorisation procedure, and the intended division of congestion income between the parties involved.

As the Allocation Approach would rely on regulatory changes intended to allocate this income to generators, one would not expect the allocation of this income to result in the need for a state aid assessment. However, to the extent that state aid is an issue for the Redistribution Approach discussed above, it would seem to apply in this case also.

Cross-zonal hedging

If the congestion income allocated directly to the generator reflects the generator's actual generation and actual price spreads, it would effectively ensure that the generator receives the price of the onshore bidding zone for any power it generates. It would therefore be largely equivalent to the Contracts for Difference option in terms of its risk allocation.

Political acceptability

The Allocation Approach involves some degree of transfer of power, as the income distribution model is effectively set at an EU level.

With respect to support mechanism compatibility, the Allocation Approach makes things simple in that it dispenses with the need for negotiations or the need to factor in uncertain auction revenues, which might be difficult to incorporate into some national support systems.

Scalability and adaptability

The Allocation Approach should be easy to scale and adapt if it is effected through regulation and this regulation clearly defines the rules for identifying hybrid projects and the appropriate allocation of revenue. That said, the creation of an authorisation procedure, to assist in the identification of relevant assets, could end up requiring significant resources depending on how it is designed. As such, scalability will be hampered if the approach relies on the use of case-by-case exemptions. If it is difficult to set up general rules for reallocating congestion income and as more offshore wind generators invest in the same offshore bidding zone over time, there may be a need to renegotiate the distribution of congestion income. This too will hamper scalability.

Joint Ownership Approach

Under this approach, a single legal entity would own both the network assets and the generator. In the case of multiple offshore wind generators connected to the network, all of the offshore wind generators could jointly own the network assets. With respect to operating and planning the offshore network, the model could be implemented using either:

- An independent system operator, for instance owned by one or more of the adjoining TSOs, or
- An offshore TSO

The first model would be similar to the ISO model as defined in Article 44 EU Directive 2019/944 and would require that the owner of the ISO does not have any commercial interests in power generation or consumption in the offshore bidding zone.

Dispatch

Joint ownership effectively enables the combined owner to sell power at the price obtaining in the bidding zones to which the power flows. There is no incentive to act strategically to distort the offshore bidding zone price and dispatch should be efficient as long as there is only the single operator and owner.

In the event that P2X and other wind farms are connected to the offshore network, joint ownership that excludes some network users may create problems related to non-discriminatory third-party access and de facto priority dispatch of the integrated generator. These problems may be alleviated, at least partially, by the presence of a strong ISO. However, there is no denying that the joint ownership model results in intrinsic incentives to discriminate in favour of the network owners' assets.

Investment

With respect to offshore generator and network investments, all benefits and costs are directly internalised (onshore network costs must still be handled through a charging framework). Where an onshore TSO is the owner, there may be a risk of cross-subsidisation between the offshore and onshore network.

With an offshore TSO, the owner's incentives to act strategically with respect to dispatch and the distribution of network costs may deter P2X and independent generator investors. This risk of discrimination may, in part, be mitigated by ensuring that new market parties are represented as part owners of the conglomerate, but would not eliminate the problem entirely, with potentially skewed incentives related to ownership shares and governance arrangements. With a properly regulated offshore ISO however, we would expect such problems to be eliminated or at the very least be significantly reduced.

As the Joint Ownership Approach is not in line with current regulatory principles at the EU level, or indeed nationally, we consider it unlikely to result in a stable investment environment and likely to be subject to significant changes over the assets' lifetime.

Regulatory compliance

The Joint Ownership Approach is in direct conflict with unbundling requirements for transmission ownership. If the offshore network were to be operated by an ISO, the existing regulatory framework for (onshore) ISOs could probably be used to regulate this organisation to a large extent, although some tailoring may be required to address the specific needs of jointly owned hybrid projects.

Cross-zonal hedging

The integrated company would have a physical hedge in the form of their transmission assets, effectively accessing the onshore market directly.

Political acceptability

The Joint Ownership Approach is likely to entail major changes to the way offshore network assets are currently organised and regulated and may therefore face political opposition due to the difficulty involved in integrating this approach within existing national regulatory structures.

Scalability and adaptability

This model is likely to be very difficult to scale effectively. With multiple network users, collective ownership will become increasingly impractical and one could well see the creation of two classes of network users, those who own the network and those that do not. For those that are not owners, the model would cease to serve its original purpose of enabling investment decisions based on the cumulative generation and congestion income impacts. Further, ensuring non-discrimination between these different classes of users, as well as among the different owners would likely require complicated systems of internal governance and oversight that may act as a bureaucratic brake on further development of the offshore network.

Summary of options' properties

In the table below, we summarise the properties of these options according to each of the evaluation criteria.

Table 5: Summary of the Approaches

	Redistribution	**Allocation**	**Joint Ownership**
Dispatch	Efficient with provisions	Efficient	Efficient for owner, less certain for other market parties connected to the offshore network unless offshore ISO is established
Investment	Environment: Uncertain Generator: OK with provisions Network: OK P2X: OK	Environment: Uncertain Generator: OK Network: OK P2X: OK	Environment: Very uncertain Generator: OK Network: OK P2X: Uncertain[20]
Regulatory compliance	Medium-Low	Low	Very Low, although offshore ISO can mitigate somewhat
Cross-zonal hedging	Medium-High depending on mechanism	High	High
Political acceptability	Medium	Medium	Low
Scalability and adaptability	Low to Medium depending on mechanism	Medium	Low

Clearly the Joint Ownership Approach reflects a very significant break from current regulatory principles and is liable to open up a range of new challenges. Fundamentally, it sets up incentives for the network owner to discriminate against other current or potential network users. Although the creation of a strong ISO could mitigate the scope for these incentives to seriously impact operational decisions, the approach establishes a questionable foundation for the development of a large-scale offshore network with multiple users and may end up proving difficult to scale as a result.

The remaining approaches reflect a trade-off between the extent of the regulatory reform required and the ease of scaling up. They also reflect different regulatory strategies. Whereas enabling the redistribution of congestion income would represent partial deregulation of the area, direct allocation entails creating new regulation.

Given the limited experience with hybrid projects, we believe that adding regulation to directly allocate congestion income to generators is probably premature and risks locking in bad outcomes due to an inability to foresee the practical challenges involved in the development and management of such projects. Enabling redistribution by, for example, amending regulation to explicitly allow congestion incomes to be redistributed to generators connected to hybrid assets is therefore likely to be a more prudent approach because it implies a greater degree of flexibility in developing solutions that work for specific projects.

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[20] Strictly speaking, this uncertainty applies to any subsequent investor that does not form a part of the original jointly owned entity. It reflects the fact that the original owners may have incentives to discriminate against subsequent investors, either directly, as part of the management of the original assets, or else by minimising the newcomers influence in any expanded conglomerate structure.

A well-designed redistribution mechanism could also enable different types of generation projects to compete on an equal footing for public support, possibly as part of existing support mechanisms, and support a transition to purely commercial investment. For example, the redistribution mechanism could be designed to ensure that a hybrid project has market price and network cost exposures that are equivalent to that of a direct-to-shore connection, allowing these two types of projects to compete for support on a consistent basis. Provided that the redistribution mechanism is established independently of any public support arrangements, the redistribution mechanism could endure following the end of public support and could even be used for projects developed on purely commercial terms.

The Redistribution Approach should, of course, also be evaluated against leaving current regulation unchanged and, for example, compensating generators through existing revenue support mechanisms. Arguably, partially deregulating restrictions on the use of congestion income could weaken investment in cross-zonal capacity. However, we consider that this impact is likely to be negligible where the deregulation is limited to offshore hybrid projects and more than offset by the benefit to cross-zonal capacity associated with enabling the development of hybrid projects.

Price manipulation in small bidding zones

Offers for power in an offshore bidding zone are likely to come from relatively few sources compared to an onshore bidding zone. In the case of a simple interconnector tie-in, like that depicted in Figure 8 for example, power is only sourced from the offshore generator and a low-priced power market. In some setups, it may be relatively easy therefore, from a technical standpoint, for the offshore generator to influence the clearing price in the offshore bidding zone, both because the effective offer prices of other providers become easier to anticipate and because the generator's own generation is pivotal in determining the zone's clearing price.

That said, because the bidding structure in the zone is so simple and the offshore generator's marginal generation costs are likely to be fairly close to zero and well understood by regulators, any price manipulation by offshore generators is likely to be conspicuous. As a result, the technical possibility for manipulation is unlikely to be a serious concern even for very small offshore bidding zones, provided some rudimentary regulatory oversight is in place.

Looking to the future, however, things may be rendered more complicated by the introduction of adjustable sources of power consumption, for example for hydrogen production, within small offshore bidding zones. For small zones, the consumption decisions of a large consumer could easily be pivotal in determining the zone's clearing price. Given sufficiently large consumption volumes and sufficiently large price differences between power in connected bidding zones, such consumers could potentially restrict their consumption below the economically efficient level in an attempt to reduce the clearing price of power in the zone and thereby reduce their aggregate costs.

This challenge is, at this stage, theoretical in nature and European legislation already includes measures to tackle price manipulation. As a result, we note this challenge more for completeness than because we believe it requires an immediate remedy.

2.4 Conclusions

As set out in this chapter, the bidding zone definitions implied by the Home Markets and Offshore Bidding Zones options give rise to multiple challenges under the current market arrangements. Some of these challenges can be fully or partially addressed by additional modifications to the market arrangements. Where appropriate, we have assumed that these additional modifications are a part of the relevant option, as summarised below.

Under the Home Markets option, and in relation to the challenge of allocating offshore transmission capacity between offshore generation and cross-zonal flows, we assume that offshore injections are given priority access to offshore network capacity through the creation of a new form of priority access for these projects. This is a very important assumption and entails significant regulatory change. In relation to cross-zonal capacity calculation, TSOs are assumed to maintain the same responsibilities they hold today regarding the need to anticipate the residual transmission capacities available for trade, despite the additional challenges involved. On balancing and redispatch, offshore generators are assumed to enjoy broadly similar access to the market. However, they may be prevented, through national regulation, from netting any imbalances that they have with onshore Balancing Responsible Parties as part of the local settlement process. No special measures are implemented with respect to the redistribution of revenues, but generators are assumed to contribute to the costs of the internal network through connection charges and/or network tariffs.

Under the Offshore Bidding Zones option, no special measures are required to address the allocation of offshore transmission capacity or cross-zonal capacity calculation. In relation to balancing and redispatch, a distinct imbalance settlement price is created for the offshore bidding zone that reflects the marginal cost of balancing there. The System Operator is able to balance the offshore system with the help of onshore Balancing Service Providers. It achieves this both through cross-zonal balancing markets and, potentially, direct integration with an existing onshore TSO. Regarding the redistribution of congestion incomes, we avoid making any strong fixed assumptions but predominately consider cases in which the current regulation regarding the distribution of congestion incomes either remains unchanged or is relaxed such that the generator can effectively receive the price of a connected high-price zone to which it exports. Specifically, as noted in the section entitled 'Summary of options' properties' beginning on page 35, we consider that enabling revenue redistribution between transmission and generation owners by relaxing restrictions on the use of congestion incomes for hybrid projects may be an appropriate solution to support the development of hybrid projects under the Offshore Bidding Zones approach. However, a more detailed consideration of the options available is likely warranted given the broader focus of the current study and the practical challenges that may be involved in implementing the different options.

3 MODELLING ANALYSIS

As part of this study, we have conducted detailed dispatch modelling of the Home Markets and Offshore Bidding Zones arrangements. The modelling shows that, provided the network topology avoids the presence of structural congestion between offshore hubs and their home market, differences in pricing and revenue outcomes will generally be limited between the options. That said, where network congestions are not well reflected by the use of home market bidding zones, generator revenues can be reduced when moving from the Home Markets to Offshore Bidding Zones case. Any reduction strongly depends on the relevant network topology. For the specific network configuration modelled, we observe an average overall reduction in generator revenues of 1-5% but significant reductions of up to 11% in limited cases. European welfare is potentially lowered under the Home Markets option. Given the assumptions made, notably in relation to the priority network access afforded to offshore generation, the welfare losses identified in the modelling are exclusively the result of offshore wind injections blocking exports from negatively priced onshore markets. For the modelled scenario, these annual welfare losses rise from less EUR 1 million in 2025 to slightly less than EUR 20 million in 2050. These losses depend on the potential value of the displaced trade and therefore on the frequency and scale of negative prices, as well as the network topology's ability to transfer power between onshore zones in the absence of offshore generation. Where negative prices onshore result from limited system flexibility, rather than feed-in-tariffs, the associated losses reflect true reductions in overall welfare. Note that these losses do not cover the additional financial costs of congestion management by System Operators under the Home Markets option, costs which will ultimately be funded by network users.

3.1 Modelling Approach

3.1.1 Scenario assumptions

The modelling analysis is based on system context assumptions taken from THEMA's "Emissions Eliminated" scenario. This scenario describes a world in which the Paris Agreement targets are fulfilled and further developed, so that global GHG emissions approach net zero by 2050. The scenario implies virtually no GHG emissions in Europe by 2050.

This scenario is consistent with the development of at least 70 GW of offshore wind capacity in the North Sea by 2030 – the indicative aggregate capacity target noted in the NSEC Joint Statement of 20 June 2019.[21]

Below we give a short overview of the main assumptions relevant for the model analysis. Commodity and carbon price assumption are summarized in Table 6. Carbon reaches price levels of EUR 150 per tonne by 2050, consistent with the marginal costs of abatement needed in the industrial sector to reduce GHG emissions to the targeted volumes. As for gas prices, we assume a gradual increase towards 2040, before prices decline again towards 2050 as a result of diminishing gas demand. Coal prices stay low along the entire model period; the importance of coal prices for power prices declines strongly in the 2020s as most coal capacities are phased out.

Table 6: Commodity and carbon price assumptions, real 2020 values

	Unit (real 2020)	2025	2030	2035	2040	2045	2050
CO_2 Price	EUR/ton	35	47	63	84	112	150
Gas price	EUR/MWh	24	29	30	29	28	25
Coal price	USD/ton	61	55	54	51	51	51

[21] https://kefm.dk/media/12744/joint-statement-on-the-deliverables-of-the-energy-cooperation-between-the-north-seas-countries.pdf

The analysed hub structure (see Section 3.1.2) involves the countries Germany, Great Britain, France, Netherlands, Belgium, and Denmark. Demand assumptions for these regions are summarised in Table 7. The Emissions Eliminated scenario assumes an increasing degree of electrification of transport and industry, resulting in a significant increase in conventional power demand over time, consistent with the overall emission ambitions.

In addition to conventional demand, we also modelled sector coupling and power-to-gas demand. In such a scenario, power-to-gas is a key element in the energy and industry transitions and also provides flexibility for the power sectors, including in the form of power-to-gas-to-power. Assumed power-to-gas volumes are included in Table 7 for the six countries relevant for the modelled offshore infrastructure.

Table 7: Demand assumptions in the hub region, TWh per year

		2025	2030	2035	2040	2045	2050
Germany	Electricity demand (incl. losses)	616	671	718	769	788	796
Great Britain	Electricity demand (incl. losses)	317	339	379	416	440	450
France	Electricity demand (incl. losses)	507	534	558	584	593	598
Belgium	Electricity demand (incl. losses)	95	102	111	120	123	124
Netherlands	Electricity demand (incl. losses)	124	133	144	156	160	161
Denmark	Electricity demand (incl. losses)	46	54	61	69	69	69
All regions	Power-to-gas demand	6	77	203	424	675	846

Finally, our assumptions for renewable generation are summarised in Table 8. The assumptions for long-term renewable build-out are based on official targets, and combined with an assessment of cost developments in the different regions in order to derive scenario consistent renewable volumes. Taking into account power-to-gas demand, wind and solar account for 85% of the total demand in the six countries by 2050. Remaining demand is almost entirely covered by hydro, bio, and some CHP capacity. Coal is entirely phased out, and gas only plays a minor role as a provider of flexibility rather than significant energy volumes.

Table 8: Assumed wind and solar generation, TWh

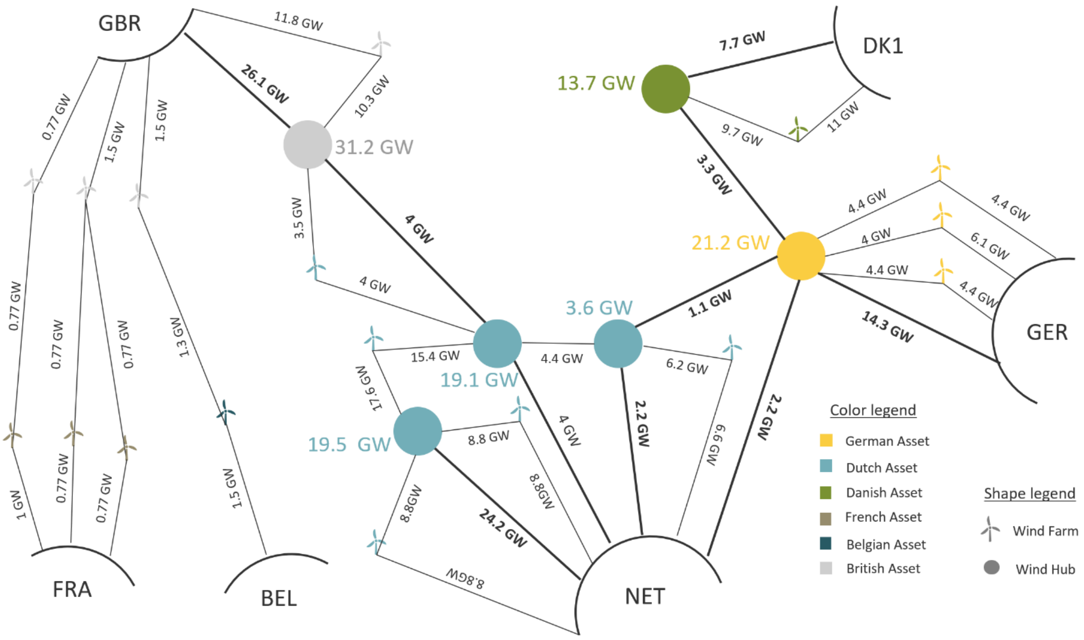
		2025	2030	2035	2040	2045	2050
Germany	Wind	170	238	348	427	493	511
Great Britain	Wind	151	230	291	359	450	491
France	Wind	83	134	236	349	436	504
Belgium	Wind	17	31	42	45	50	54
Netherlands	Wind	58	101	145	212	255	280
Denmark	Wind	25	47	60	75	85	89
Germany	Solar	75	128	180	217	254	273
Great Britain	Solar	13	19	28	32	36	40
France	Solar	44	68	101	159	215	250
Belgium	Solar	8	13	15	21	25	26
Netherlands	Solar	18	24	38	46	48	49
Denmark	Solar	3	5	6	7	8	10

3.1.2 *Assumptions on the offshore infrastructure*

The structure of offshore generation and transmission assets assumed for the North Sea are based on the European Centralised Hubs – High Wind scenario from Work Package 12[22],[23] of the PROMOTioN[24] study. The PROMOTioN study seeks to analyse and support the development of meshed HVDC offshore networks. Note that all offshore connections developed in the model are hypothetical and do not represent any actual ongoing projects.

The implied configuration of assets in 2050 is illustrated in Figure 9. As can be seen, the French and Belgian assets are not part of a complicated hub infrastructure, but rather form a kind of chain interconnection between these countries and Great Britain. Non-hybrid projects are not shown. The scenario is based on the general idea that wind assets across the North Sea are connected to offshore hubs that are linked to shore. In total, the hubs and wind farm capacities in Figure 9 represent about 45% of the 70 GW target in 2030.[25] The other 55% is assumed to be installed via direct-to-shore connections and are accounted for in the modelling.

Figure 9: Illustration of the Topology Assumed in the Model Analysis in 2050



The aggregate wind generation capacity included in these hybrid structures is shown in Figure 10.[26] As can be seen, the bulk of the generation capacities connected to hybrid projects are German, Dutch, British and Danish wind parks, meaning that they are built within those country's Exclusive Economic Zone (EEZ).

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[22] See in particular: https://www.promotion-offshore.net/fileadmin/PDFs/D12.2_-_Optimal_Scenario_for_the_Development_of_a_Future_European_Offshore_Grid.pdf

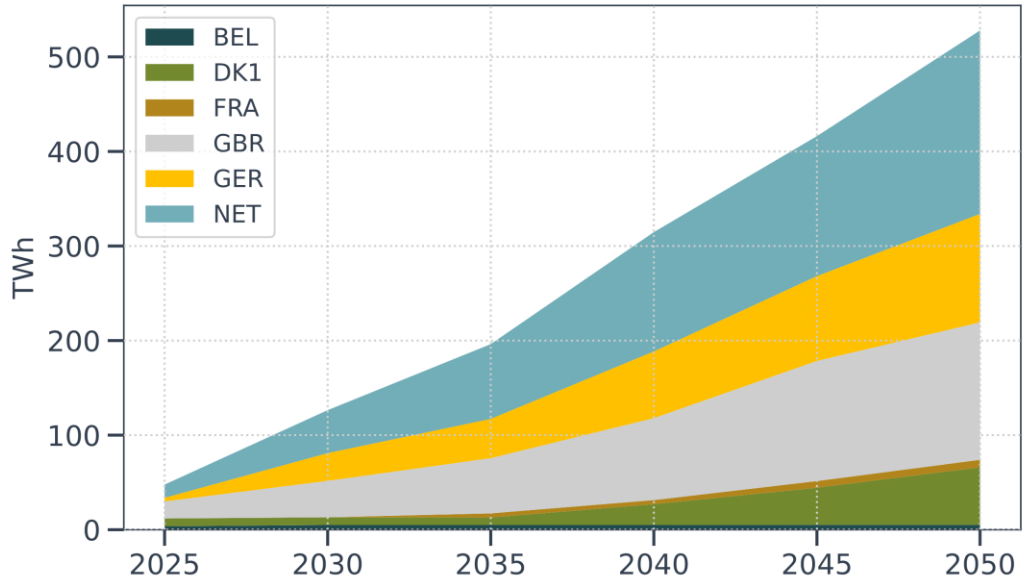
[23] Numbers and transmission capacities are based on the study. However, some changes to the topology were made and a 10% increase in transmission capacity was included to allow for more trade between onshore zones.

[24] PROgress on Meshed HVDC Offshore TransmissIOn Networks

[25] See the Joint Statement on the deliverables of the energy cooperation between the North Sea countries.

[26] Wind capacity of the farms is excluded from the image. The largest wind farm size is of 2 GW, and the transmission capacity to shore is always large enough to evacuate wind generation of the asset. .

Figure 10: Generation from Hybrid Projects



3.1.3 Model setup for the Offshore Bidding Zone and Home Market cases

Simulations for this study were performed using the TheMA power market model. The model is THEMA's proprietary power market model and is an advanced, fundamental power market model covering European markets. The model has been used for a variety of purposes including the preparation of price forecasts, scenario analysis and investment evaluations. A wide range of actors within the European power sector license the model for direct use and the model's userbase includes public authorities, energy utilities, portfolio managers and funds. The model is constantly updated, maintained and improved in close collaboration with these licensees.

The model is a fundamental power market model that optimises welfare under a set of restrictions, such as trade limitations, start-up restrictions, availabilities of power plants, intertemporal hydro restrictions, etc. This approach mimics today's market clearing algorithm. Fundamental power market models are commonly used in scenario assessment and are the industry standard for modelling future years.

One outcome of the algorithm is trade flows consistent with welfare maximisation and subject to the physical constraints assumed in the scenarios. For countries, wind farms, or hubs connected via DC (direct current) lines, this implies that power typically flows from low price areas to higher price areas. When countries are connected via offshore hubs, residual trade capacity is utilized accordingly.

For this assessment we modelled two cases, one in which the wind farms and hubs are represented by separate bidding zones (Offshore Bidding Zones case), and one in which the wind farms and hubs are part of its home market (Home Markets case).

The Offshore Bidding Zones case

In this setup, each hub and wind farm illustrated in Figure 9 represents a bidding zone. Note that it is not the case that each individual wind farm forms its own bidding zone. In practice, each hub shown in the figure represents clusters of wind farm capacity that are not shown individually.

Trade between these hubs, wind farms, and connected regions and countries is limited by the trade capacities on each line, based on the PROMOTioN study assumptions mentioned above.

Dispatch, as well as the utilisation of infrastructure for trade via the hubs and farms is then optimised by the model. This implies that:

1. Wind is dispatched first to countries with highest prices (subject to transmission capacities)

2. Remaining transmission capacities are utilised such that trade always flows from low-price bidding zones to high-price bidding zones.

For the reasons discussed in section 2.3.4, the prices in offshore bidding zones may be different from the price in the associated home market.

We assume that the marginal cost of offshore generation is zero, implying that if the price in the relevant bidding zone falls to or below zero, offshore generation curtails voluntarily. Such self-curtailment by offshore generation frees up transmission capacity that would otherwise be used to evacuate the offshore generation. This released transmission capacity may alternatively be used to flow power between onshore zones.

The Home Markets case

In this setup, the wind farms and hubs become part of its home market, and dispatch responds according to price signals provided by the home market. This implies that, if the price in the home market is larger than zero, wind dispatch has priority over trade.

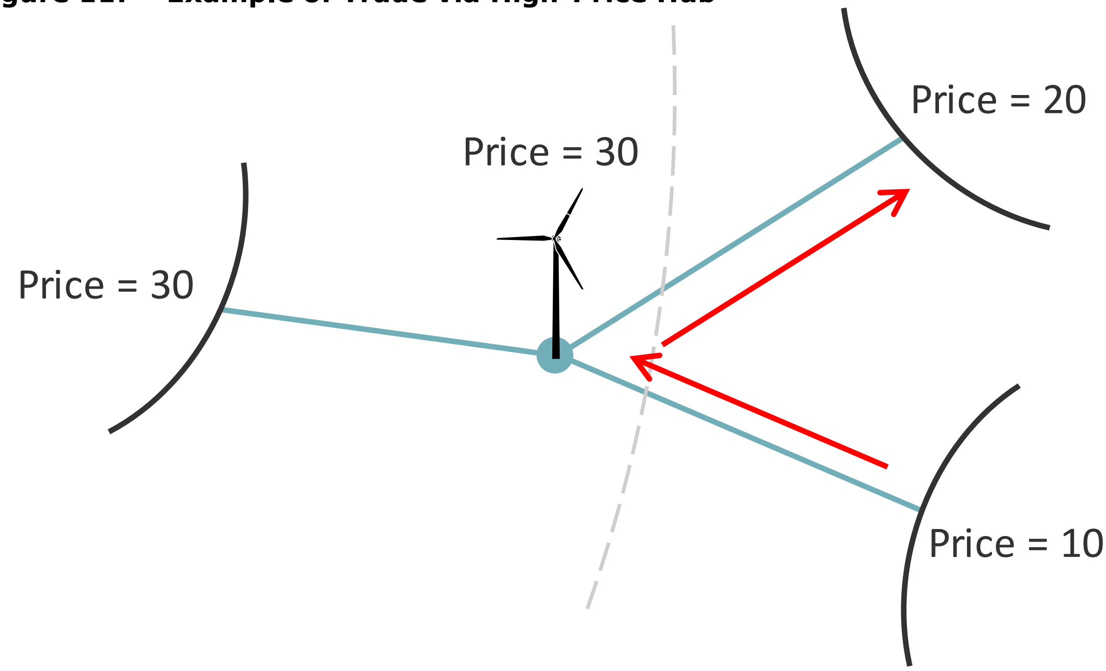
In consequence, offshore injections are always accepted at the hub if the home market price is above zero, even if this implies flowing the power generated against a price differential. Any residual transmission capacity after accepting these injections is then used for trade. (See also the theoretical discussion in section 2.2.1.)

The model setup allows for trade flows via a high-price hub where this is efficient. In practice this means that, for configurations like the one shown in Figure 11 below, the market clearing algorithm will recognise when there is effectively cross-zonal capacity joining the price-20 and price-10 zones and will allow for flows across this capacity even though, from an infrastructure perspective, this involves flows via a higher price home market.

In practice, enabling this behaviour in the clearing process would be a key requirement as a failure to do so would result in a potentially much larger dispatch inefficiency than what we derive from our analysis (explained in further detail below).[27]

[27] Note that the necessary market behaviour can likely be implemented through the use of 'virtual hubs' when representing the structure of cross-zonal connections as part of the market clearing process. It is not expected to require any change to the market clearing algorithm. Such virtual hubs are already in use, for example to reflect the network line set on Jutland (line set DK1A).

Figure 11: Example of Trade via High-Price Hub



Modelling inefficiency and welfare losses

Given the modelling setup, as described above, flows will be identical under the two options *except* in cases where the power price in one of the connected onshore markets drops below the offer price of the offshore generator (which is assumed to be zero). When this happens, exports from the low-price market will be prioritised under the Offshore Bidding Zones setup but not under the Home Markets setup. In these situations, the dispatch solution under the Home Markets setup is inefficient with zero-priced offshore injections being used before negative-cost power, and this gives results in a welfare loss.

Under the standard set of modelling runs, we assume that power prices do not become negative and therefore this difference in overall European welfare is not observed.[28] Negative prices are often the result of a market design that results in (cost-inefficient) priority dispatch. However, they may also result from large start-stop costs for thermal generators, which discourage generators from stopping generation entirely. In a scenario with large volumes of renewables, as in our scenario, we assume an efficient market design that leads to voluntary curtailment of volumes at prices at or below marginal costs.

However, in order to demonstrate the potential welfare impacts of negative pricing, we have included some results based on a scenario where we include some inflexible renewable generation that continues producing until prices reach -50 EUR/MWh.[29] The results for this sensitivity are presented and discussed in Section 3.2.4.

Of course, the choice of the minimum price limit is arbitrary and the minimum price level influences the value of the welfare loss obtained when prices are negative. The results are therefore intended to illustrate the factors influencing welfare losses and their approximate magnitude rather than to provide an exact forecast of the expected impact.

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[28] Negative prices result, in general, from a lack flexibility and price responsiveness from both generation and demand. In some cases, generators may not be incentivised to self-curtail when prices are negative because they are receipt of generation subsidies that exceed the costs of selling additional power. In the future, improvements in system flexibility, price responsiveness and support scheme design should help to ensure that negative pricing are not occurring.
[29] This was done without changing total generation capacity.

3.2 Results

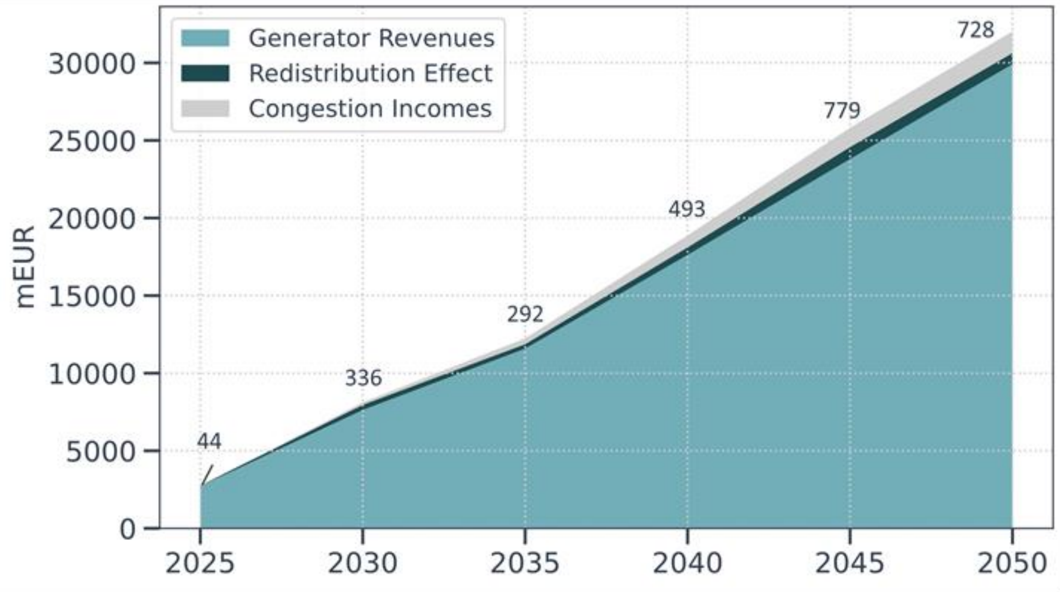
Using the approach described, we have quantified the welfare and redistribution differences implied by the Home Markets and Offshore Bidding Zones options for the selected topology.

The following sections set out the main insights from the modelling work. Section 3.2.1 covers the redistribution of revenues between generation and transmission owners, referred to hereafter as the redistribution effect. As part of this section, we consider the treatment of negative congestion incomes due to the forcing of power flows against price differentials under the Home Markets option. We also examine the relative size of congestion incomes and wind revenues. Section 3.2.2 explains the relevance of network topology in driving these earlier results and sheds some light on the implications of alternative topologies. Section 3.2.3 digs deeper into the likely implication of different options for bidding behaviour and generator revenues at specific sites. Section 3.2.4 looks at the implications for overall European welfare, i.e., the magnitude of and drivers for welfare losses. As explained above, given our assumptions, notably in relation to priority access for offshore injections, welfare losses only occur in situations with negative prices in connected onshore bidding zones. Section 3.2.5 analyses price volatility under both market arrangements. Finally, Section 3.2.6 considers the implications of offshore P2X and models price and operational dynamics under such a setup.

3.2.1 Redistribution effect

By contrasting aggregate generator and transmission owner revenues under the different bidding zone options, it is possible to estimate the overall magnitude of the redistribution of revenues between generation and transmission owners – or the redistribution effect – that stems from the choice of bidding zone design. Figure 12 below shows the total volume of revenues earned by hybrid projects over time, disaggregated by type. As explained further below, the total volume of these revenues is unaffected by the bidding zone design but the distribution of these revenues will be. The teal (light blue) area shows the minimum aggregate level of generator revenues under either option. The grey area shows the minimum aggregate level of congestion incomes, which are earned by transmission owners, under either option. The dark blue area reflects the volume of revenues that is allocated to either generation or transmission owners depending on the choice of bidding zone design and the exact height of this dark blue wedge is given by the numbers listed above the area chart. It is this dark blue wedge that shows the redistribution effect.

Figure 12: Redistribution Effect over the Modelling Period

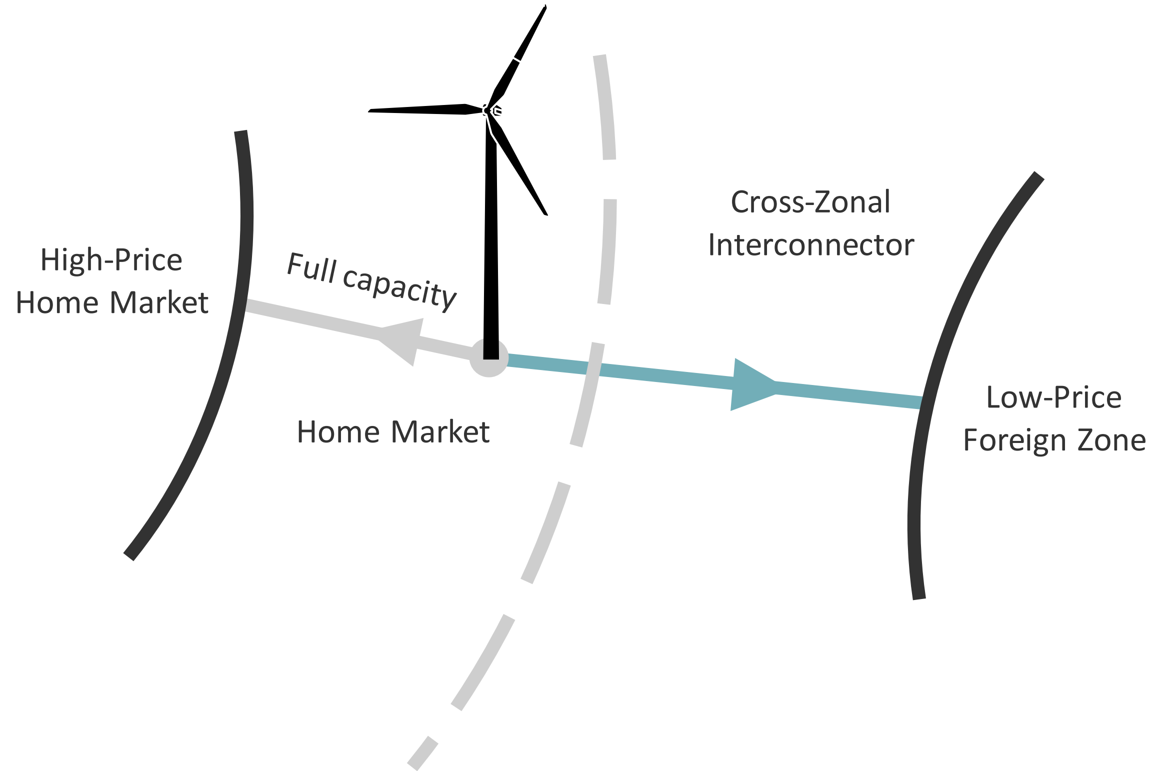


The redistribution effect, although small relative to the aggregate size of generator revenues, is significant in absolute terms, ranging from less than EUR 50 million in 2025 to almost EUR 780 million in 2045. Across the full time horizon, the redistribution effect ranges between one and five percent of total generator revenues under the Offshore Bidding Zones case. As discussed further below, the small relative size of congestion incomes and of the redistribution effect is driven by the network topology.

Note that these results assume that onshore prices do not fall below zero in any settlement period and, as such, dispatch behaviour and total welfare remain unchanged across the options. This would, for example, reflect a situation in which national support schemes are revised to prevent dispatch during negative price periods and in which there is additional flexibility on the system. A complete discussion of welfare impacts is contained in Section 4.2.1 and modelling of the case in which prices can drop below zero is covered in Section 3.2.4.

Note also that, in cases like that depicted in Figure 13, in which offshore generation must be flowed from a high-price home market to a lower-priced bidding zone due to insufficient transmission capacity from the offshore generator to the home market, we have assumed that the costs of this activity are borne by transmission owners.

Figure 13: Evacuation of Offshore Injections Against a Price Differential



In practice, what would happen in such cases, which are relatively rare in the modelling, is that the market solution would dispatch offshore generation capacity in excess of the level that could be flowed to the home market, but would not schedule any exports from the high-price home market. The System Operator would then be forced to relieve the implied congestion on the line between the offshore generator and the home market and could do so by conducting countertrades so as to flow any excess offshore generation to the low-price market. This is fully efficient, but implies a cost to the System Operator, which must buy power in the high-price market and sell it in the low-price market. It is this cost that is assumed to be borne by transmission owners in the redistribution analysis.

Such costs could conceivably be borne by generation owners, for example if the costs of this countertrade were charged back to offshore generators through use-of-system charges. Offshore generators are arguably the main beneficiaries of this activity, which prevents offshore generation from being curtailed and enables these generators to receive a higher price for the power generated than is ultimately paid by the consumers of this power. Such a charging regime would help to avoid incentivising investments in offshore generation capacity that is formally included in a high-price home market but, due to network constraints, ultimately provides power to lower-price markets. Were the costs of this countertrade activity attributed to generation owners, this would slightly reduce the size of the redistribution effect calculated above. However, any change would be small given the relatively small numbers of cases in which such countertrade occurs in the modelling.

The possible need to flow power against a price differential under the Home Markets option and its theoretical implications for dispatch efficiency are discussed further in Section 4.2.1.

Overall, the modelling results suggest that, at an aggregate level, the redistribution effect is small as a share of overall generator revenues, representing about 1–5% of generators' revenues under the Offshore Bidding Zones option depending on the year examined. A more detailed examination of specific hubs in 2050 shows that, in slightly more than half of cases, the impact is very small, with generator revenues being less than 1% smaller under the Offshore Bidding Zones case than under the Home Markets case. However, in some specific cases, the reduction in generator revenues is significant.

Across all hubs in the model, the impact of the choice of bidding zone configuration on generator revenues ranges from 0 to 11 percent, assessed as a share revenues under the Offshore Bidding Zone case. To understand what is driving this variation in local impacts, it is critical to understand the influence of the network topology.

3.2.2 Understanding the network topology and its impacts

Fundamentally, the topology defines the location of structural network congestion. Since offshore bidding zones and price splitting will occur on the basis of congestion, the topology also effectively defines the convergence and splitting of prices under the Offshore Bidding Zones option. In this way, it also defines how similar or different the Home Markets and Offshore Bidding Zones options are in practice.

The topology we have assumed implies that there is limited offshore congestion within home market bidding zones under the Home Markets option and, as a result, the Offshore Bidding Zones option often does not result in radically different price coupling and splitting results across the relevant offshore assets. In other words, although the Offshore Bidding Zones option allows greater flexibility in the determination of offshore prices, this additional flexibility rarely produces significantly different pricing outcomes because structural network congestion is anyway located at the borders of the home market zones. As a result, the size of the redistribution effect is limited.

The chosen topology also helps to explain why congestion incomes are relatively small in comparison to generation revenues. Figure 14 below shows a simplified illustration of the modelled network topology. As can be seen, the bulk of the transmission capacity is effectively dedicated to the evacuation of wind power, with relatively little transmission capacity available for trade between one onshore zone and another. In effect, the network has been designed to help evacuate power from the hubs to their home markets, with additional links between hubs added to enable trade. Congestion generally occurs on the smaller lines connecting the hubs and it is on these lines that congestion incomes are predominately earned, irrespective of the bidding zone option. Given the comparatively small size of these connections relative to the overall volume of wind generation, as well as the fact that congestion incomes are earned on price differentials, which are typically smaller than the absolute prices earned by generators, it is not surprising that congestion incomes are small relative to generator incomes.

Figure 14: Simplified Illustration of the Network Topology in 2050

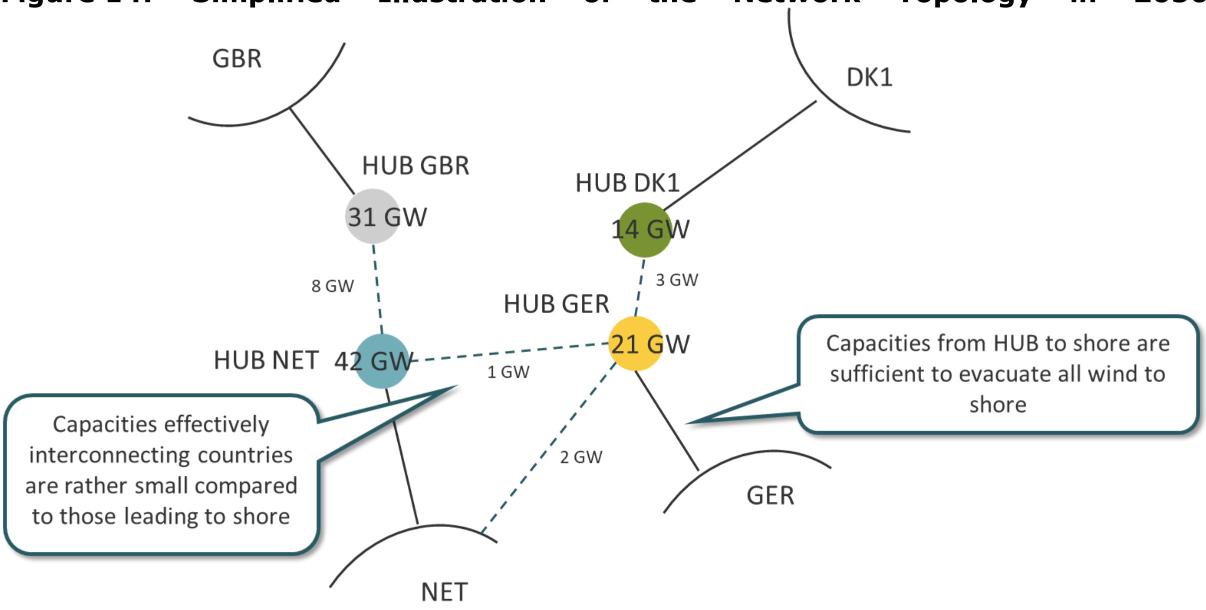
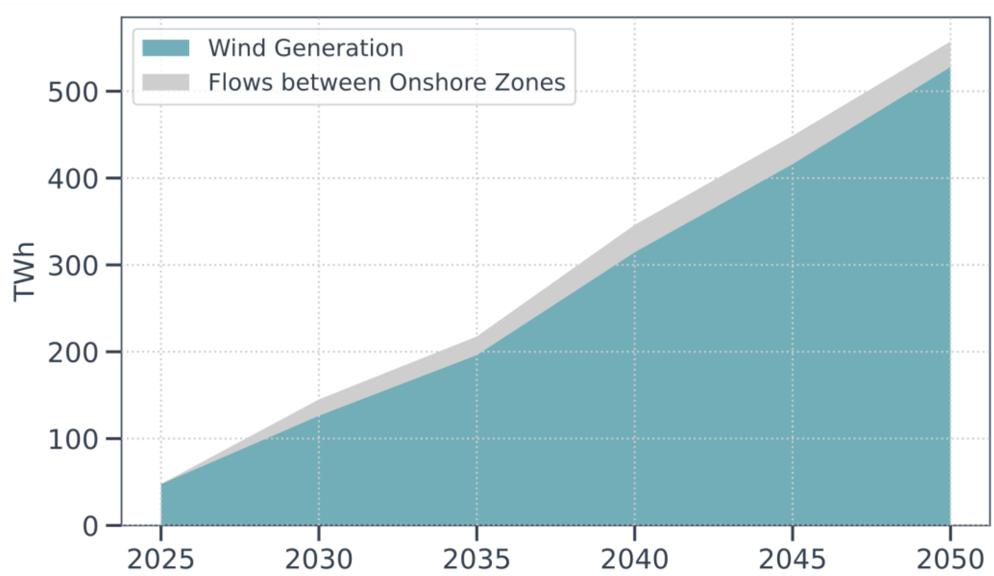


Figure 15: Wind Generation and Exports from Onshore Zones (Trade)



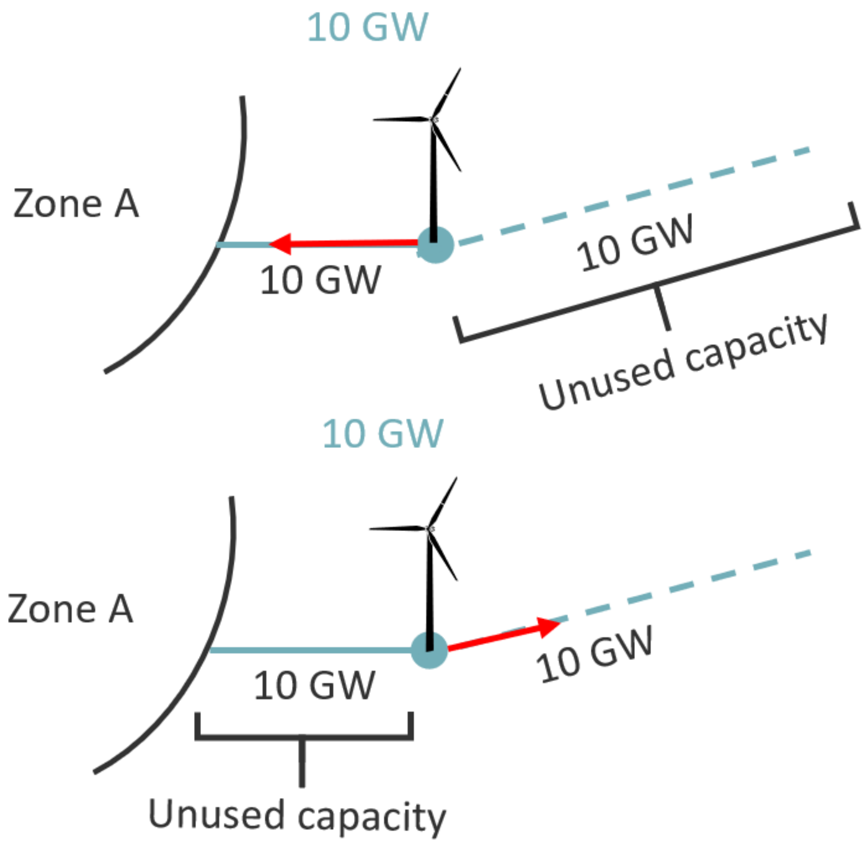
Given the significance of the topology in driving the results, including the magnitude of the redistribution effect, it is therefore important to reflect on the extent to which the analysed topology is representative of likely developments in the North Sea and to investigate the impacts under alternative topologies. In doing so, it is also relevant to recognize that the topology itself will be influenced by the choice of bidding zone design and structured to avoid congestions within bidding zones.

Looking at likely topologies from the perspective of a Home Markets arrangement, it makes sense to organise the offshore assets so as to ensure limited or no congestion between the hubs and the rest of their home market. In this case, the topology we have modelled would seem appropriate and, as discussed above, topologies like this will give rise to limited differences between the two market arrangements.

Starting from a position in which the use of offshore bidding zones is an option, it is not necessary to ensure a strong connection between the offshore hubs and any specific onshore bidding zone. Nevertheless, there may be a tendency to organise the topology such that offshore generation is largely directed to a specific onshore zone. This is because, for any offshore generation site, some markets will be expected to have higher prices and be cheaper to access and because setting up the hybrid project to allow wind generation to be evacuated to multiple different markets comes at a cost.

This cost is shown visually in Figure 16 below. Put simply, allowing greater optionality in terms of how offshore generation is evacuated implies adding more transmission capacity. Consider the extreme case of giving a dispatchable offshore generator access to a second market. In this case, the additional transmission capacity required to connect the generator to the second market will not result in any additional cross-zonal trade between the two onshore zones, since such trade is blocked by the power being evacuated along one or other line. In this case, the greater optionality in where to flow power clearly implies lower transmission asset utilisation – only one line is ever used to evacuate the power. For a non-dispatchable generator, some trade will be possible, but only to the extent that the generator is not evacuating power. Given the cost associated with greater optionality, there may still be a tendency when optimising asset configurations under the offshore bidding zone case to set up assets such that offshore generation is largely evacuated to expected high-price markets and where the pattern of flows is largely predetermined by the configuration of transmission capacities. In these cases, in which the offshore generator has ample connection capacity to the high-priced export market and imports to the hub are limited, we will again see little difference between the two options, assuming the generator is a part of this high-price export zone under the home market arrangements.

Figure 16: Example of Unused Capacity when the Topology is Designed to Allow Evacuation between Two Onshore Zones



That said, it is also important to note that the network topology analysed is not the product of an endogenous optimisation and that such an optimisation might result in a configuration that implies more congestion between offshore hubs and their home markets. Such congestion patterns might also result from network topologies in which old radially connected assets become subsequently interconnected, offshore wind assets are tied into existing interconnectors, or incremental additions to offshore wind capacity outpace additions to transmission capacity. In these cases, the generation assets may not have sufficiently large connections to their home markets to prevent differences in price formation under the two options.

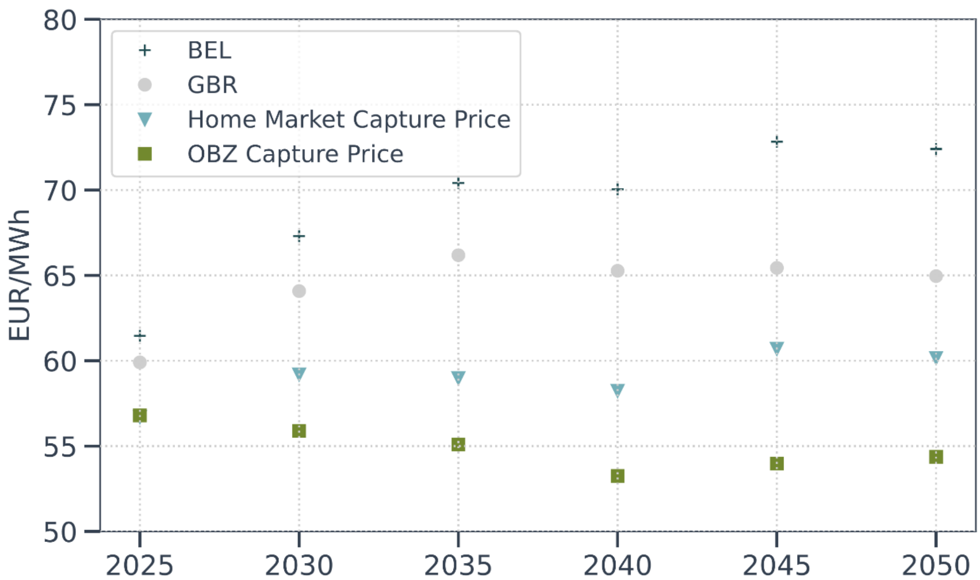
In conclusion therefore, while it isn't obvious that the modelled topology represents a special case, the small scale of the assessed redistribution effect is clearly a consequence of the modelled topology. Critically, the risk of network congestions occurring between an offshore hub and its home market is quite limited given the assumed topology and this limits any redistribution effect.

Where such congestions do arise however, a significant redistribution effect is possible and this is occasionally observed in the modelling. The reasons for these differences are explored further in the next section.

3.2.3 The impact on offshore prices

As explained in section 2.3.4, offshore wind generators potentially experience different prices under the two options. The change in prices and revenues is not uniform across all assets. Rather, the impact at a site level depends on whether there is congestion between the hub and its home market, which triggers price splitting, and, in these cases, how significant the price spread is between the connected markets. With similar prices across onshore zones, the impact of price splitting on offshore prices and incomes is fairly limited. With large price differentials, the redistribution effect is far more pronounced. Large price differentials will, other things being equal, also imply a stronger economic case for interconnection and hybrid projects.

Figure 17: Capture Price of a Belgian Wind Generator under the Home Markets and Offshore Bidding Zone Options

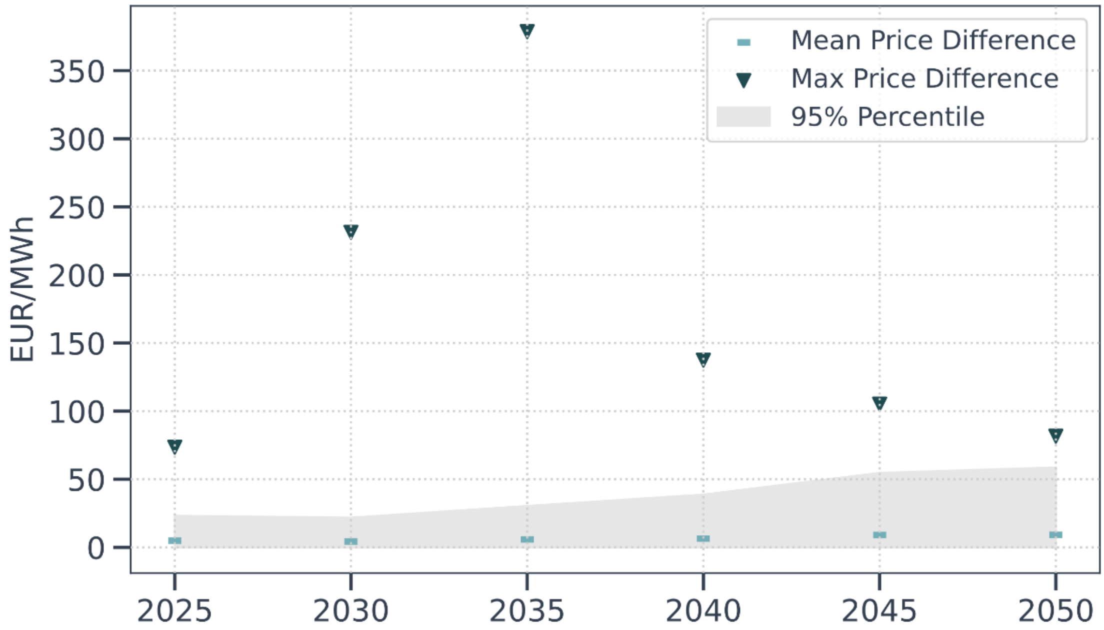


To illustrate the significance of the price differentials, Figure 17 shows the capture price[30] of a Belgian wind asset. The capacity of this asset increases from 960 MW in 2025 to 1350 MW in 2030. Critically, in 2025, the Belgian farm is only connected to its home market (a direct-to-shore connection), but, in 2030, the farm becomes incorporated into a hybrid project as transmission capacity linking Great Britain and Belgium via the wind asset comes online. The figure shows how capture prices for the generator diverge once the offshore farm becomes a hybrid project. As expected, the generator's capture price is higher under a Home Markets setup, since it is guaranteed the Belgian onshore price,

[30] Capture prices are weighted based on the generation volumes of the specific type of asset and therefore reflect the average price received for the generator's output. The zonal prices shown are averaged across all hours equally.

and the difference in its capture price between the two options becomes larger as the price spread between Belgium and Great Britain increases. The shaded area in Figure 18 indicates the range in which the hourly price differences between the two zones typically lie. As the shaded region grows, the difference in capture prices under the two market arrangements becomes larger.

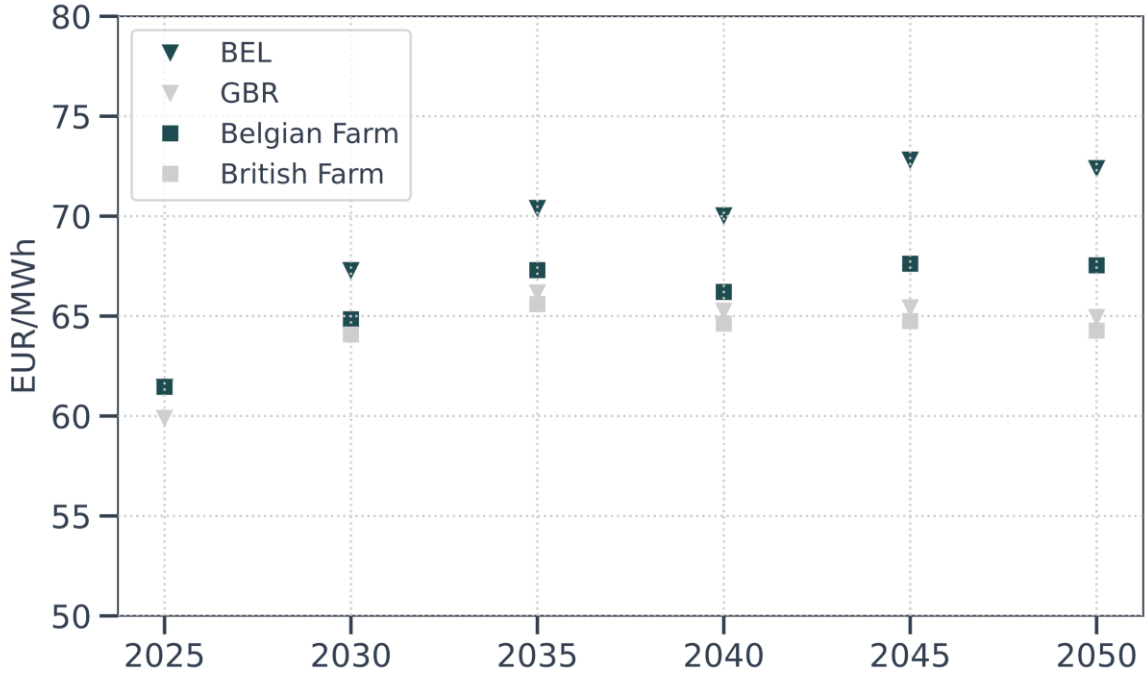
Figure 18: Price Spreads between the Belgian and British zone



Naturally, higher capture prices imply larger revenues for the offshore generator. For this specific wind park, the price differential results in a revenue difference of around EUR 18 million in 2030 (when capture prices under the different market arrangements diverge), rising to EUR 30 million by 2050. As mentioned before, this difference in revenues does not reflect an overall change in economic welfare, rather this is simply a redistribution between generation and transmission asset owners.

In this particular example, the hybrid project consists of a transmission line that links two wind parks, one British and one Belgian. As covered previously in the discussion of pricing dynamics in Section 2.3.4, these farms effectively compete with exports from low-priced connected zones and may have to accept a lower price in order to be dispatched under the Offshore Bidding Zones model. Since the British windfarm is assumed to have the low-priced British market as its home market, the price it receives is not significantly different under the Home Markets and Offshore Bidding Zones options. However, the Belgian farm, which has a relatively high-priced home market, must compete with cheap exports from the British zone and thus must accept lower prices in some hours under the Offshore Bidding Zones option. Again, the difference in the offshore generator’s revenues are mirrored by changes in transmission owner’s congestion incomes. The difference between the farms in the size of this redistribution between generation and transmission owners is shown in Figure 19 below. More generally, we conclude that the difference in generator revenues under the two options is greatest for generators connected to high-price home zones and the size of the difference depends on the size of the price spread between their home market and the potential export zones connected by the hybrid project.

Figure 19: Clearing Price of a Belgian and British Offshore Wind Farm and their Connected Onshore Zones under the Offshore Bidding Zones Option



3.2.4 Dispatch inefficiency in the Home Markets setup

As discussed further in Section 4.2.1, the assumed priority access given to offshore generation can lead to dispatch inefficiency in the case were prices in the connected onshore areas drop below the offering price of the generator. We assume that offshore wind is offered at a price of zero. As a result, this inefficiency only arises in the modelling when prices in the connected onshore areas become negative. If the marginal costs of offshore generation are higher than assumed, for example due to the need for additional maintenance, then true welfare losses would be greater than estimated below.

The cause of the inefficiency is the dispatch of zero-cost wind ahead of negatively priced exports from one or more interconnected neighbouring zones. Ultimately this inefficiency reduces overall European welfare. The scale of the loss depends on the forgone value of this potential trade from negative priced zones, as discussed further below.

We have modelled this inefficiency as described in Section 3.1.3. Our results show that, for the assumed frequency and scale of negative prices shown below, the welfare loss ranges from EUR 0.5 million in 2025 to almost EUR 20 million in 2050.

As this welfare loss relates to the value of trade blocked by the priority dispatch of wind, its size is limited by the volume of transmission capacity than can be used for trade from one onshore bidding zone to another. All else equal, network topologies that allow for larger volumes of trade when offshore generation self-curtails will give rise to larger welfare losses. So, an interconnector tie-in topology, like the one depicted in Figure 7, in which the volume of transmission capacity is symmetric in either direction is able to fully utilise transmission capacity for trade in the absence of offshore generation and will be worse affected than a setup in which the size of the cables is very asymmetric and only a portion of transmission capacity can be used for trade when wind self-curtails. The latter topology will be relatively limited in term of its ability to support trade and so will be less affected by the resultant inefficiency.

The size of the welfare loss is also proportionate to the price differential between zones when prices do go negative. Very large spreads imply that the failure to trade is far more harmful. As such, in a system that is well-interconnected through dedicated interconnectors or in which there is greater flexibility, price spreads are likely to be more limited and so the welfare loss implied by this forgone trade smaller.

Figure 20: Evolution of the Welfare Loss Throughout the Modelling Period

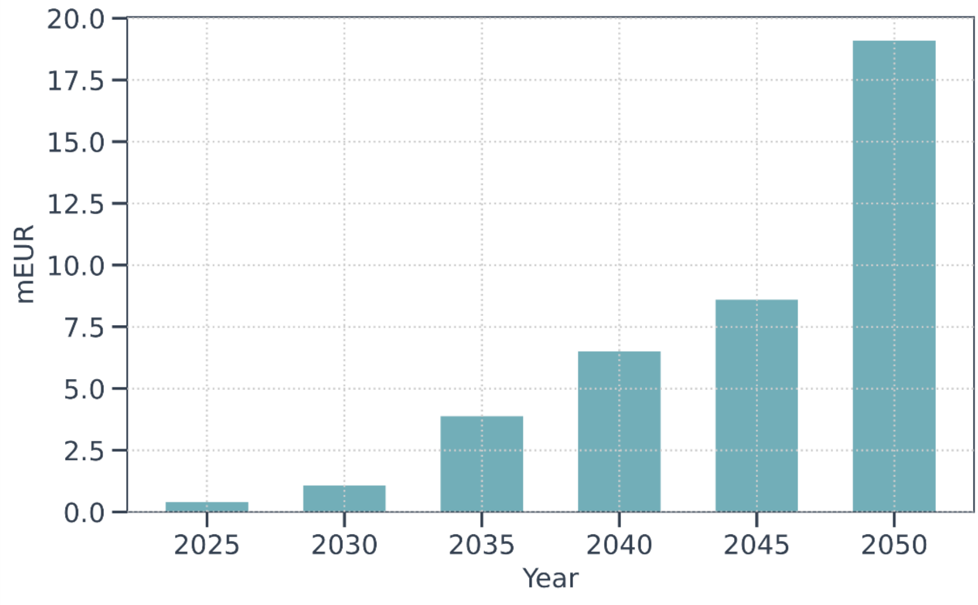


Figure 21: Frequency of Negative Prices for Each Zone in Every Modelling Year

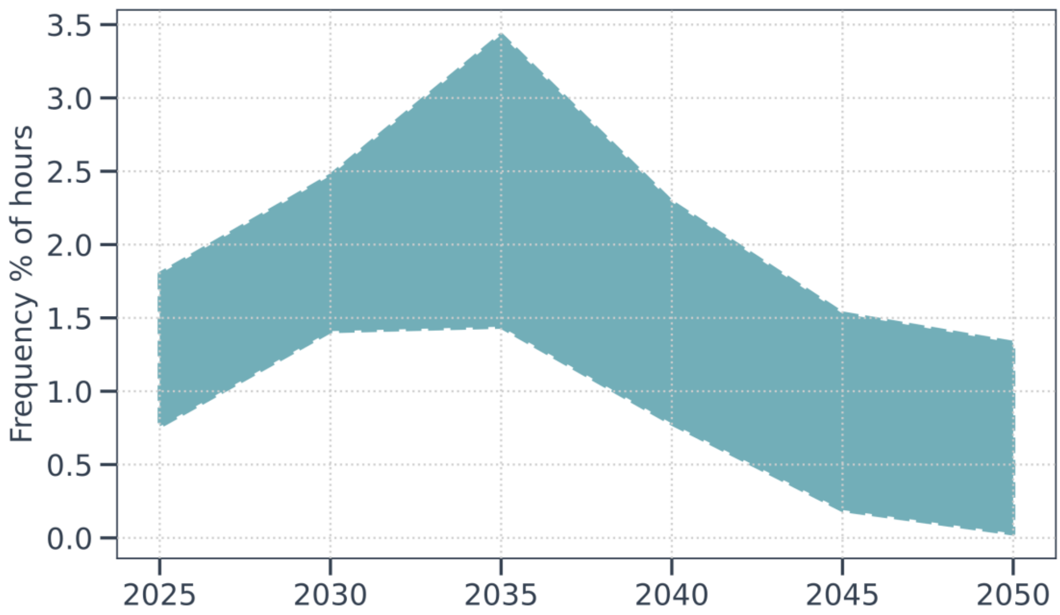
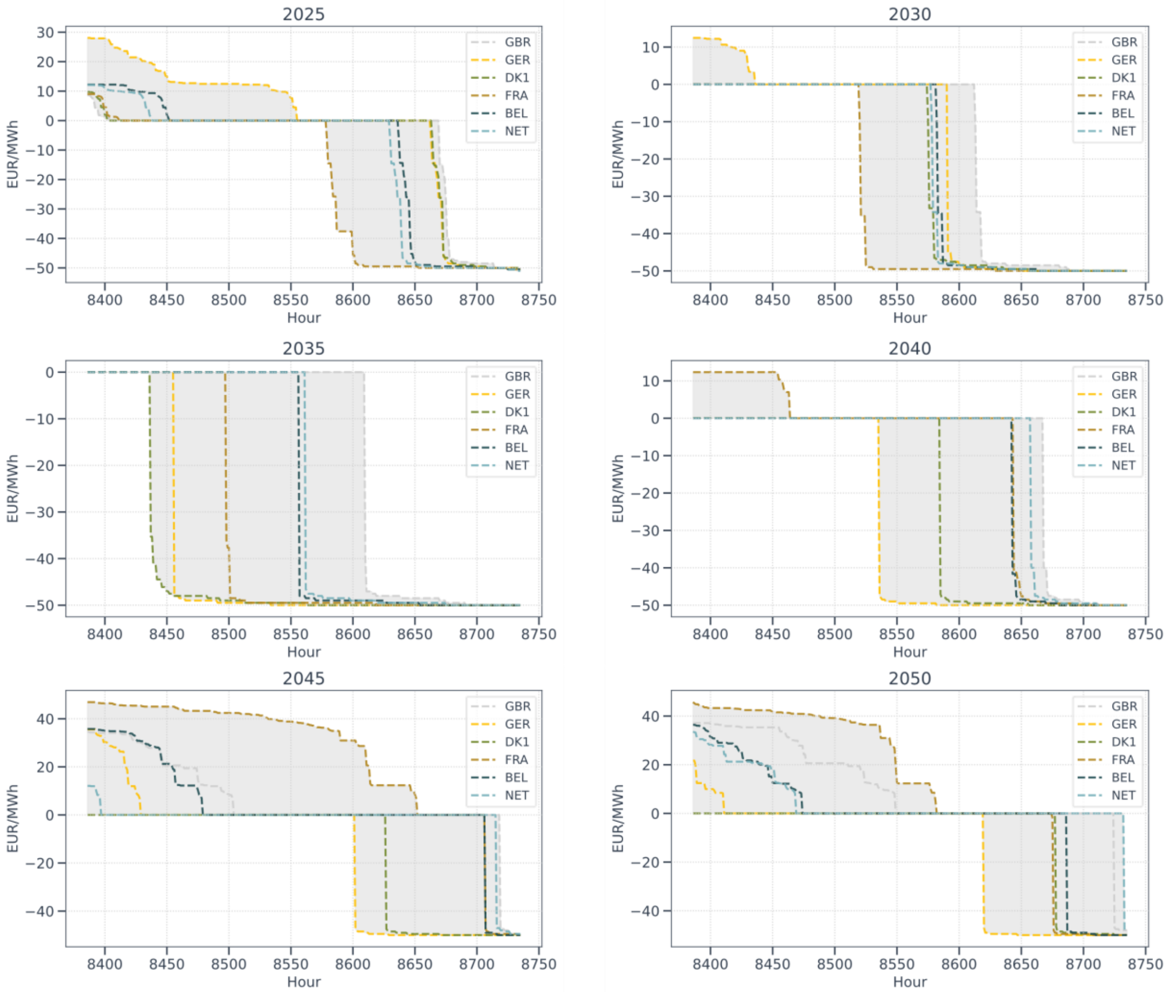


Figure 22: Tail of the Price Duration Curve for All Modelling Years



3.2.5 Price volatility under different market arrangements

Neither market arrangement appears to result in greater overall levels of price volatility, although the structure of prices at specific locations can be affected by the bidding zone choice. Again, the nature of these impacts is heavily influenced by the specifics of the local topology.

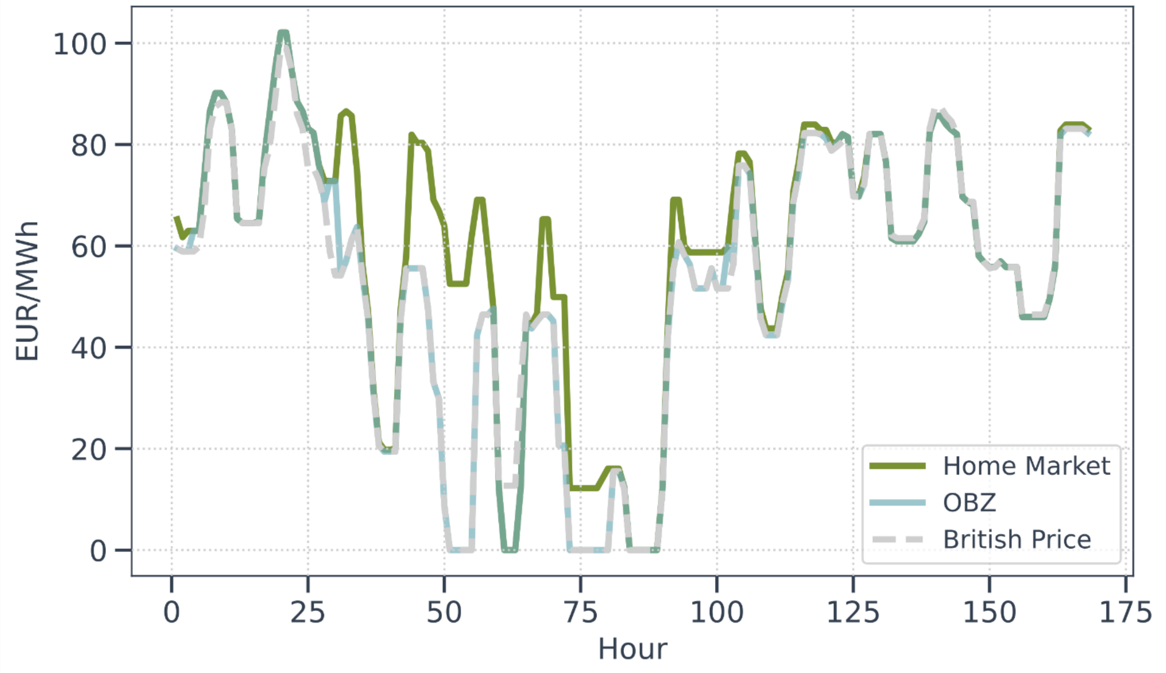
Under the Home Markets option, price volatility is inherited from the home market. For the Offshore Bidding Zones option, changes in flows and congestion patterns can potentially result in the offshore price jumping between the prices of neighbouring markets, increasing the price volatility. However, Offshore Bidding Zones can also be a source of price stability, enabling the offshore price to split from the onshore price when that price heads off to extreme levels.

In the modelled topology, the offshore hubs have strong transmission links to their home zones. As discussed previously in Section 3.2.2, this limits the variation in pricing across the two options and limits the extent to which volatility is different. It's also worth noting that price spikes typically occur when generation is low and therefore when offshore generation is likely to be low. As such, even if the transmission capacity connecting the hub to shore were comparatively limited, a lack of generation in peak price hours might still result in offshore prices that are coupled with the high onshore price. Of course, this is not always the case, but this correlation between low wind output and high price periods also contributes to the similarity in prices and volatility under both market setups.

As discussed in Section 3.2.3, hubs with low-priced home markets will tend to experience comparatively little difference in price coupling, and therefore in price volatility, under the different options.

A snapshot of the 2050 price volatility for the Belgian windfarm used in the example above is shown in Figure 23, to give a sense of the possible price structure and how this might differ between the two options.

Figure 23: Hourly Power Prices for a Belgian Wind Farm in Week 39, 2050



3.2.6 P2X operations

As part of this work, we have also considered briefly the implications of the alternative market arrangements for P2X development and modelled the dynamics of P2X operation under the Offshore Bidding Zones model.

It must be noted at the outset that investment in offshore P2X is very unlikely to be economically rational under a Home Markets arrangement. By definition, this arrangement ensures that prices are identical on- and offshore. Building P2X capacity offshore therefore provides no price benefit and entails the additional costs and risks associated with offshore development. For this reason, we have looked primarily at how P2X might work under an Offshore Bidding Zones option.

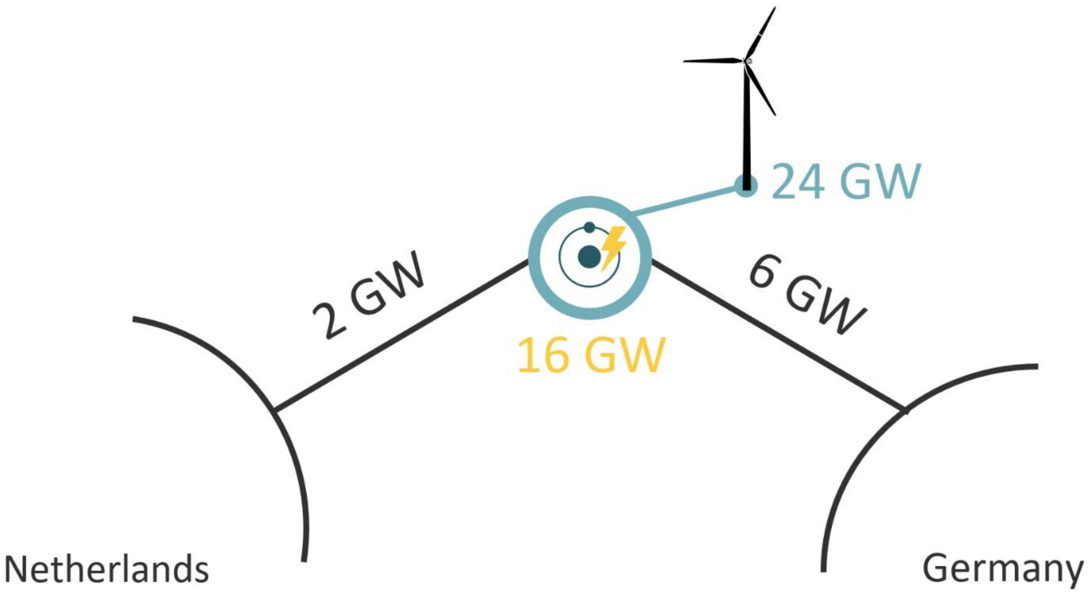
The rationale for placing P2X offshore is to displace the need for costly power transmission capacity. Since our assumed network topology generally includes sufficient transmission capacity to evacuate offshore generation to shore, it isn't a particularly relevant case for thinking through pricing dynamics and P2X operations at a hub where P2X is being used.

Instead, we have modelled the dynamics of an offshore P2X hub that combines electrolysis capacity with limited transmission capacity. This could represent either a situation in which power transmission capacity from the offshore hub to shore is limited, or a situation in which power can be transported to a P2X facility onshore, but onshore transmission capacity is insufficient to transmit power from the shore to consumers elsewhere on shore. In the latter case, the 'offshore' zone is assumed to include the relevant landing zone. Under this setup, the offshore bidding zone price can potentially decouple entirely from that in the connected zones. The possibility of lower power prices than in neighbouring zones may motivate an investment case for offshore P2X.

The setup modelled is shown in Figure 24 below and involves a hub with 16 GW of electrolyser capacity. As noted above, this setup is equivalent to one in which the P2X facility is physically located onshore, but transmission capacity between the landing area and the rest of the onshore market is limited by the capacities shown. The power prices assumed for Germany and the Netherlands are based on the results from the Offshore Bidding Zone setup in 2040. Due to the higher prices experienced in Germany relative to those in the Netherlands, more transmission capacity is assumed towards Germany. However, aggregate power transmission capacity from the hub is far below the hub's generation capacity.

For the purpose of illustration, we have assumed that the electrolysis capacity is willing to purchase power at a price of 5 EUR/MWh. This assumed willingness-to-pay will frequently determine the clearing price at the hub.[31]

Figure 24: Modelled Electrolysis Example for a Two-Shore Hub.



To understand how the electrolysis capacity operates under such a setup, it is useful to examine operations over a representative week. Figure 25 below shows flows to and from the hub, as well as generation and consumption over the week. Initially, wind generation is below the transmission capacity from the hub to Germany. This results in imports from the Netherlands and no use of the electrolyser. As the wind assets start producing more power, the transmission capacity linking the hub to both Germany and the Netherlands becomes congested, and the electrolysis capacity begins to consume the locked-in wind. The consumption of the electrolyser follows the pattern of wind output to absorb any power that cannot be evacuated to shore.

Figure 26 below shows price developments during the same week. As expected, we see that hub prices are coupled with the onshore markets in hours in which the transmission capacity is not fully utilised. However, the hub price decouples when wind generation becomes locked-in and is set instead by the bid price of the electrolysis capacity. The extent of decoupling and electrolysis consumption is therefore heavily dependent on the relative scale of transmission capacity available and the generation profile of the wind park. Looking at mean annual prices in both the onshore zones and the hub, it is clear that the price experienced at the hub can be significantly lower than that onshore. In this example, the average price at the hub was 36 EUR/MWh, significantly lower than the 65 EUR/MWh seen in the Netherlands and almost half of the average price of 75 EUR/MWh in Germany.

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[31] We also modelled this setup using different assumed prices for electrolysis demand. Changing the electrolysis bid price from 0-15 EUR/MWh moves the mean price experienced at the hub from 33 to 42 EUR/MWh.

Figure 25: Operational Dynamics for Electrolysis Capacity in a Two-Shore Hub

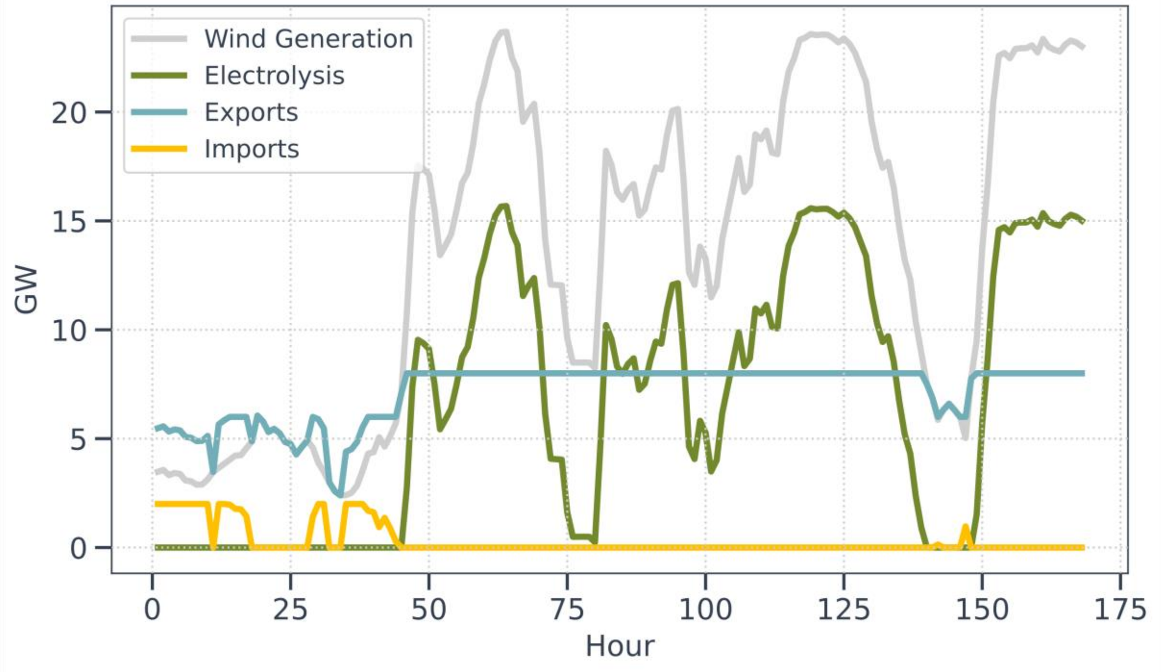
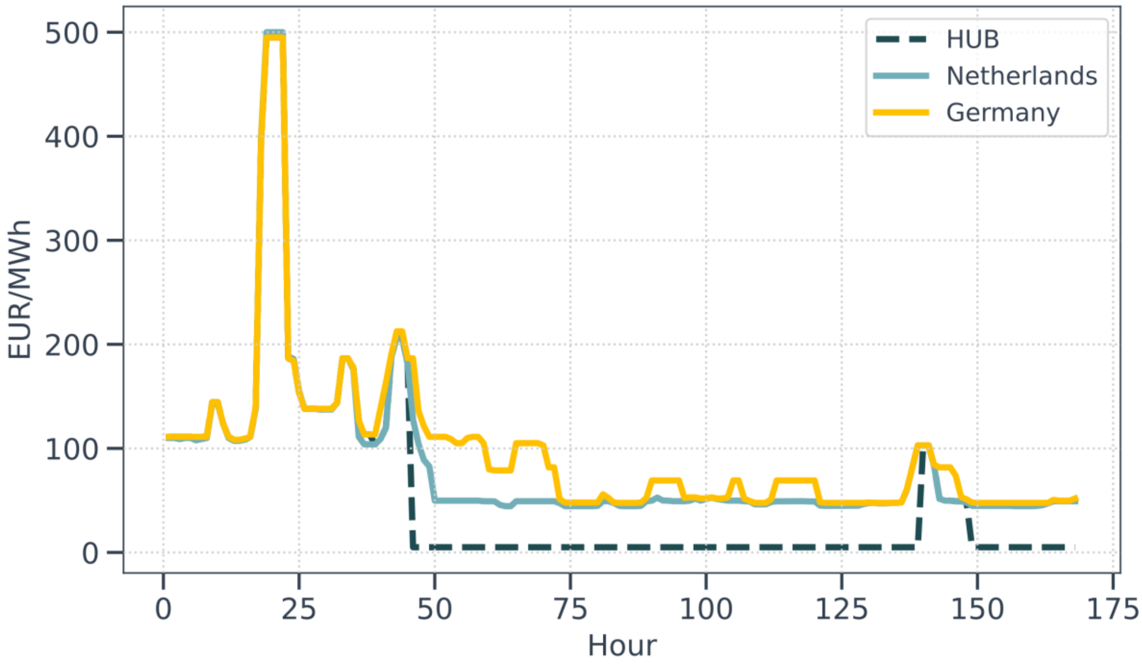


Figure 26: Hub Price Coupling and Decoupling in a Two-Shore Electrolysis Hub



In conclusion, offshore P2X is unlikely to make sense under a Home Markets arrangement, since the offshore price cannot be advantageous relative to onshore production. The use of offshore bidding zones, in contrast, might facilitate offshore P2X. Specifically, in cases where offshore generation cannot be evacuated to shore, the offshore power price may be significantly lower than the onshore price. When modelling the operational dynamics of such a setup, the electrolyser effectively acts as a residual source of demand and activates to absorb any generation that cannot be evacuated. This reflects the assumed merit order of demand, with onshore consumers willing to pay more for power than the offshore P2X facility. As shown in this example, the offshore P2X producer may effectively determine the offshore price when wind is locked in. This highlights the need for suitable arrangements between the P2X producer and generators to ensure the viability of investment for all parties. It also underlines the potential market power of large power consumers in such a small zone.

4 ASSESSMENT OF ALTERNATIVE MARKET ARRANGEMENTS

This section contains a detailed assessment of the market design options against a comprehensive set of criteria. The Offshore Bidding Zones approach is found to better support dispatch efficiency and to be better able to adapt to future changes in both the topology of offshore assets and the broader structure of the power system, including the mass deployment of offshore generation. This option is also more consistent with the current regulatory framework, notably avoiding the use of potentially discriminatory priority access, and therefore more likely to support a stable long-term investment environment. In contrast, the Home Markets option is better able to support some forms of commercial investment, notably in generation, since it tends to increase capture prices and limit the share of total revenues tied up in congestion income.

In this chapter we go through each of the assessment criteria set out in Table 9 below and contrast the performance of the Home Markets and Offshore Bidding Zones arrangements.[32] **A summary of the overall assessment is provided in Section 6.**

4.1 Assessment Criteria

In assessing the alternative options described above, we have used the assessment criteria set out in Table 9 below. This table should not be read to imply that each of these criteria are of equal importance. Rather the table provides a comprehensive account of the various factors considered. In reaching our overall recommendation in Chapter 6, we have placed particular emphasis on the need to secure the long-term efficiency of the market and to avoid undue discrimination among market participants.

Table 9: Assessment Criteria

Criteria	Question (Is the option good?)
Dispatch	
Efficiency	Is the market dispatch solution efficient (total social welfare)?
Market manipulation	Is there low risk of market manipulation?
Investment – Environment	
Predictability	Is the investment / regulatory environment predictable / stable?
Investment – Generator	
Commitment to a hybrid configuration	Can a generator prefer a hybrid configuration to a direct-to-shore configuration?
Viability	Is commercial investment in generation capacity viable given the distribution of revenues and risks?
Efficiency	Are generator revenues likely to provide efficient investment incentives?
Support schemes	Are efficient national support systems feasible under the option?
Investment – Network	
Viability	Is commercial investment in transmission capacity viable given the distribution of revenues and risks?
Efficiency	Are network revenues likely to provide efficient investment incentives?

[32] The two approaches are assessed here as being mutually exclusive and, indeed, for any specific area, only one approach could be applied. It is conceivable that different approaches could be followed in different sea basins, for example. In this case, the legal framework governing the prioritisation of offshore injections, among other issues, would likely need to vary across regions. Were the two approaches to both be used in different areas, the assessments here would still apply to the relevant regions.

Investment – P2X	
Viability	Is investment in P2X capacity viable given the distribution of revenues and risks?
Efficiency	Are P2X revenues likely to provide efficient investment incentives?
Balancing and Congestion Management	
Efficiency	Will balancing and congestion management be efficient?
Support for flexibility	Will the arrangements enable the use of flexibility to support integration of variable generation?
Curtailment	Will the arrangements limit curtailment?
Regulatory Compliance	
Consistency	Is the option consistent with existing European regulation?
Cross-Zonal Hedging	
Viability	To what extent is long-term cross-zonal hedging feasible?
Political Acceptability	
Subsidiarity	To what extent does the option avoid a transfer of power to a supranational level?
National flexibility	To what extent does the option provide flexibility in the sharing of costs or in the choice of a national regulatory model (e.g. related to interconnection, TSO regulation or renewables support)?
Discrimination	To what extent does the option avoid undue discrimination between different market actors? (Level playing field)
System security	
Operational security	To what extent does the option support operational security and/or generation adequacy?
CZC Certainty	To what extent does the option give TSOs' certainty over available cross-zonal capacity?
Scalability and Adaptability	
Adaptability	To what extent can the option adapt to the gradual expansion and extension of offshore capacity?
Anticipatory investment	To what extent does the option facilitate anticipatory investments?
Futureproofing	To what extent is the option future-proofed against large volumes of offshore generation, complex offshore networks and the presence of offshore loads?

4.2 Dispatch incentives and efficiency

In this section, we consider the extent to which the market design supports efficient dispatch behaviour and limits the risk of market manipulation.

4.2.1 Dispatch efficiency

Is the market dispatch solution efficient (total social welfare)?

The Offshore Bidding Zones approach is the natural extension of the principles underlying the current market arrangements to a future offshore network and results in efficient (welfare-maximising) dispatch behaviour. Specifically, bidding zone borders are defined to reflect the presence of structural network congestion. This ensures that the market dispatch solution accurately reflects the technical limits of the network and thereby limits the need for countertrade and redispatch by system operators in order to realise a feasible dispatch solution.

In contrast, and as described in section 2.2.1, the Home Markets arrangements result in offshore generators' injections becoming internal flows and, without the prioritisation of these injections over cross-zonal flows, this setup would likely result in significant dispatch inefficiency. This inefficiency would be so severe as to make the option unviable. We have therefore assumed throughout that offshore generators' injections are prioritised. This eliminates the most serious challenge to dispatch efficiency under the Home Markets option but creates serious challenges for regulatory compliance and political acceptability, which we return to below.

It is also worth noting that a simple prioritisation of offshore injections does not completely eliminate all potential sources of dispatch inefficiency. There remain two potential sources of dispatch inefficiency under the Home Markets arrangements. These relate to:

1. Cross-zonal flows from negative price zones; and

2. The evacuation of offshore injections against a price differential.

We explain both in detail below.

Cross-zonal flows from negative price zones

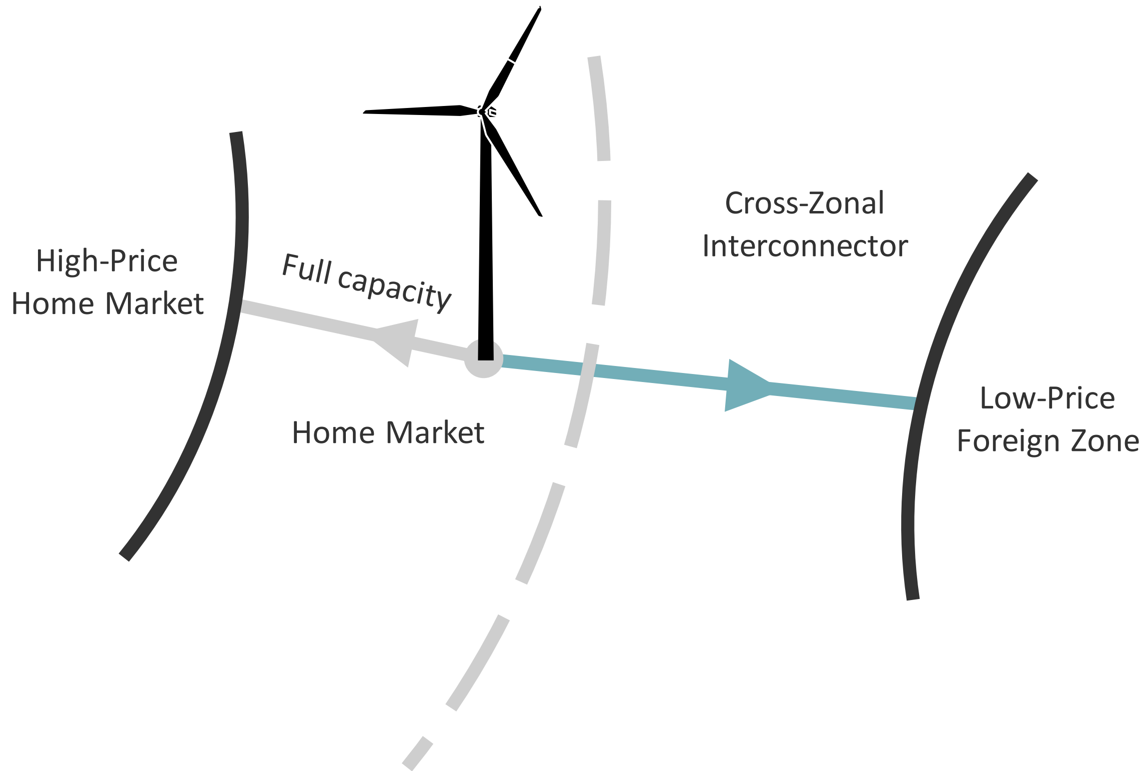
The prioritisation of offshore injections implies the prioritisation of offshore dispatch. Offshore dispatch is given priority ahead of generation capacity in an exporting onshore zone that would alternatively have made use of the scarce transmission capacity. This is only efficient where the economic costs of dispatching the offshore generator are less than or equal to those of the marginal onshore generator. Given that the offshore generator will typically be an offshore wind park with effectively zero marginal dispatch costs, prioritising dispatch from the offshore generator is likely to be efficient most of the time. However, one can easily imagine cases where this is not the case. In particular, if the exporting onshore zone has a negative price, power from this zone is even cheaper than generating at zero cost offshore. Indeed, in this case, the Home Market would be paid to take power from negative price market. Preventing imports of this negative cost power by prioritising offshore generation is inefficient. In such cases, it is actually more efficient to curtail offshore output so as to ensure as much of the negatively priced power can be transferred as possible. A failure to do so under the Home Markets option would actually result in a welfare loss.

This dispatch inefficiency only occurs when onshore bidding zone prices fall below the marginal costs of offshore generation. In today's market, we observe large and protracted negative prices in some markets. However, these large negative prices are primarily due to deficiencies in the design of national renewables support schemes, some of which stimulate generation even during periods when the power provided has a negative value. Where negative prices are due to generators' desire to secure support payments, a failure to use this subsidised power under the Home Markets option may not reflect a genuine social welfare loss. If support scheme designs are improved so as to incentivise supported generators to curtail their output during periods where there is excess generation and new sources of flexible demand are added to the system, negative prices may become less of a feature of the future market. Without negative prices, the difference in the social welfare impacts of the Home Markets and Offshore Bidding Zones options disappears since the priority given to offshore injections can no longer inefficiently displace imports of even cheaper power from neighbouring zones.

The evacuation of offshore injections against a price differential

There may be instances in which generation at the hub is sufficiently large relative to the capacity of the associated transmission connection that more than one of these cables is needed to evacuate all of the power produced. Under the Home Markets option, this may result in situations in which wind injections must flow against the cross-zonal price difference. An example of this is depicted in Figure 27 below.

Figure 27: Evacuation of Offshore Injections Against a Price Differential



In this example, generation at the hub exceeds the capacity of the transmission cable connecting the offshore generator to its home market. The excess power must therefore flow to the low-price foreign power zone. Importantly, this solution is likely efficient. Assuming the low-price foreign zone still has a positive price, it is better to export this (free) power than to curtail the wind used to generate it.

However, the above case raises the difficult question of how the system would realise this efficient outcome in practice, since it implies flowing power against the price difference. As described in section 3.2.1, the current market clearing algorithm would, in this example, not schedule flows from the high-price to the low-price market. Instead, it would incorrectly assume that the offshore generation will enter the home market, resulting in too little generation being scheduled in the home market and too much generation being scheduled in the foreign zone. As a result, system operators will need to step in to fix the flawed market dispatch solution, for example via countertrade, buying power in the high-price home market and selling it in the low-price foreign zone. This implies a cost to the system operator, and ultimately system users.

In our modelling, we effectively assume that system operators fix the market outcome as described above such that, in the end, dispatch remains efficient and there is no resultant welfare loss. However, if the system operator cannot find mechanisms by which to fix the market clearing outcome, the Home Market solution will be inefficient even with the priority access afforded to offshore generators.

Overall conclusion

Overall, the Offshore Bidding Zone option is clearly superior in its ability to ensure the efficiency of dispatch even under the problem cases described above. Although we make the strong assumption that offshore injections get priority access under the Home Markets option, there remain some potential sources of dispatch inefficiency under the Home Markets arrangements. These include the possibility that offshore generation will limit the transmission capacity made available to export power from negative price zones. The absolute size of any welfare loss resulting from this inefficient dispatch behaviour depends heavily on how prevalent negative prices are in the future power market. Improvements in the design of support mechanisms and in the availability of sources of flexibility may help ensure that negative price periods are rare. Social welfare may also be harmed if offshore assets are configured in such that a way that offshore generation must be evacuated against a price differential and out-of-market arrangements are not developed to facilitate this. If we are happy to assume that negative price periods are limited in future and that offshore assets are configured such that power need not be flowed against a price differential, then the two options are likely to be similarly efficient, with little difference in their welfare impacts. However, ultimately, the Offshore Bidding Zones approach is capable of ensuring dispatch efficiency even where these assumptions do not hold and where offshore injections do not receive priority access.

4.2.2 Market manipulation

Is there low risk of market manipulation?

Both options give rise to possible avenues for abuse.

Offshore bidding zones may, given their relatively small size, create additional opportunities for market manipulation. Participants' bids and offers are more likely to be pivotal in determining the clearing price and market players are more likely to be able to anticipate their impact on price determination. Given the relative simplicity of the zones however, any manipulative behaviour would probably be easily detected, since generators' offer prices should be well-below the expected clearing price in most cases and their offer volumes should follow relatively mechanistically from their own expectation of output. This may be more difficult for sources of offshore demand.

Under the Home Markets options, offshore generators may be able to influence the capacities made available for cross-zonal trade, since these capacities depend on their own expected injections. However, the extent of this influence is likely to be fairly indirect provided that available cross-zonal capacity is not mechanistically determined based on non-binding generation estimates provided directly by the generators.

Overall therefore, the Offshore Bidding Zone approach appears to be at greatest risk of market manipulation, even if this risk is considered manageable.

4.3 Investment

In this section, we consider the options' impact on the investment environment and on the efficiency of the investment incentives as they apply to developers of offshore generation, network investors and possible P2X projects. We also consider issues related to the viability of investment and the likelihood of developer support for the use of hybrid project configurations.

4.3.1 Environment

Is the investment / regulatory environment predictable / stable?

The Home Markets option implies two important regulatory commitments that may prove challenging to maintain in the future and may therefore give rise to some uncertainty about the long-term stability of the regulatory environment. Specifically, it implies a commitment to keep offshore generators in the same bidding zone as the rest of the home market, or at least its major centres of demand, as well as a willingness to grant offshore injections priority access to offshore transmission capacity, as discussed in section 2.2.1. In contrast, the Offshore Bidding Zones option does not entail any strong regulatory commitments that appear susceptible to review. Only the additional mechanisms related to the redistribution of revenues, discussed in 2.3.4, entail potentially reversable regulatory commitments and, for those specific options requiring less significant regulatory reforms, there is likely to be less pressure to reverse initial decisions at a later date.

At the core of the Home Markets option is a commitment to keep offshore generation and the home market in the same bidding zone. However, this commitment would seem to be under constant threat of reversal as a result of a formal bidding zone review process as described in Article 32 of Regulation (EU) 2015/1222. It may also be put under pressure as a result of changes in the configuration of offshore assets that make the dispatch results under the Home Markets option increasingly difficult to accept (see for example the case discussed in Figure 27).

The Home Markets option also entails granting offshore injections unprecedented priority in terms of their network access, as discussed in more detail in section 4.5 below. Assuming granting such priority does not violate Article 102 of the Treaty on the Functioning of the European Union, it may still be seen as discriminatory (see 4.7.3) and may result in dispatch inefficiency (see 4.2.1).As such, it is also susceptible to repeated calls for review.

In short, the regulatory commitments that underpin the Home Markets approach would seem to be subject to a perpetual risk of a political reversal because they are out of line with the regulatory principles underpinning the market arrangements onshore and imply the need for out-of-market adjustments, which may become increasingly large and hard to justify as the scale of the offshore network and of offshore generation increase. Thus, it is not clear that policy makers can credibly make the commitments implied by the Home Markets setup, since these can always be reversed by future lawmakers facing a different set of challenges. Astute, long-term investors will be aware of this risk even if current lawmakers do not intend to retroactively alter the market arrangements.

In contrast, the core of the Offshore Bidding Zones approach is in keeping with the current regulatory setup and fits well within the broader principles of market design that inform the current regulatory environment. As discussed in section 2.3.4, mechanisms to redistribute revenues under the Offshore Bidding Zones are likely to require regulatory reform and these areas may be prone to regulatory instability. However, options like providing a limited exemption to the sharing of congestion incomes would seem to be less prone to constant pressure for regulatory change than, for example, the introduction of priority access under the Home Market option.

Overall, we conclude that the Offshore Bidding Zones option is less likely to be subject to regulatory instability because it entails the need for less controversial changes to the regulatory environment and is less prone to inefficient or perverse dispatch behaviour following changes in the configuration of offshore assets. As such, it should support a more stable investment environment.

4.3.2 Generator

In this section we consider to what extent commercial developers will choose to pursue hybrid projects rather than direct-to-shore connections and the commercial viability of investment in generation. We also consider the efficiency of market investment signals in generation and how easily national support schemes will be able to efficiently support hybrid generation projects.

Commitment to a hybrid configuration

Can a generator prefer a hybrid configuration to a direct-to-shore configuration?

Developers may directly determine or otherwise influence whether a generation project is developed as a hybrid project or as a traditional direct-to-shore connection. If hybrid projects are to be developed, it is therefore advantageous if generation developers can, where hybrid configurations are socially beneficial, support their use in preference to the use of direct-to-shore connections.

There are at least four effects that are relevant to consider in this regard: those on operational risk, network costs, transmission access and the effective capture price.

On operational risk, a hybrid project will tend to provide more options to evacuate power to land relative to a direct-to-shore connection. This may provide some additional operational resilience. This is a feature of the physical setup of the system however and is unaffected by the choice of market design. As such, the choice of design will not influence generators' willingness to consider hybrid projects on this basis.

On network costs, hybrid projects may imply lower effective network costs relative to direct-to-shore connection, as the transmission assets used to connect the generator now effectively serve a wider set of users. The extent to which these savings are shared with generators is not however defined directly by the market design options. To the extent that the Offshore Bidding Zones option implies that offshore generators are exempt from contributing to the costs of the cross-zonal transmission assets that connect them to shore, given their cross-zonal nature, it might make hybrid project setups relatively more attractive than direct-to-shore connection. However, so much depends on the specifics of the national approach for the allocation of transmission costs that one cannot draw any strong conclusions as to whether the choice of market design impacts the attractiveness of hybrid configurations.

On transmission access, it is important to note that under the Offshore Bidding Zone approach, the offshore generator does not have guaranteed transmission access to the would-be home market. Specifically, the market clearing solution under the Offshore Bidding Zone approach may choose not to dispatch the offshore generator in order to free up transmission capacity for cross-zonal flows in cases where the market price in a connected market is lower than the offshore generator's offer price. This is not discriminatory, but accurately reflects a fundamental difference between a hybrid project and a direct-to-shore connection. In contrast, under the Home Markets options, the generator is shielded from this difference between the hybrid and direct-to-shore setups by the assumed (and arguably discriminatory) priority access given to offshore injections.

Whether or not this theoretical difference in the options is material for the generator's investment case will depend on how likely it is for prices in the connected markets to effectively undercut the generator's offer price. However, this difference may give developers pause when considering whether to connect a project as part of a hybrid setup.

Overall however, it is the consideration of the effective capture price received by the generator that is probably of greatest importance to a generation developer's willingness to pursue a hybrid project. As discussed previously, the use of Offshore Bidding Zones may reduce a generator's capture price due to price dynamics at the hub. Assuming that the generator's capture price is not effectively set through a public support mechanism, the extent to which the generator is left worse off under the hybrid setup depends on the details of the proposed network topology and whether or not the generator has access to the congestion income earned on the transmission assets, as discussed in detail under section 2.3.4.

Where a generator effectively receives all the congestion income earned evacuating its output to its home market, a hybrid project is unlikely to result in lower generator revenues than a non-hybrid alternative. However, the creation of mechanisms to enable this redistribution of revenues between transmission and generation owners is far from certain and would likely require changes to existing regulation.

For those projects developed on the basis of publicly funded contracts for difference, the developer is likely to be insulated from the capture price effects noted above. However, the introduction of new bidding zones under the Offshore Bidding Zones option will likely require some national support schemes to be updated to account for the change in bidding zone configuration. This issue is discussed further in the section on support schemes below.

Overall, we conclude that generators could prefer a hybrid configuration to direct-to-shore connection under either market design. However, the Home Markets option inherently shields generation developers from the potential downsides of a hybrid configuration, namely the lack of firm transmission access to a home market and a potentially reduced capture price.[33] As a result, the Home Markets option is more likely to secure developer commitments to hybrid projects relative to the use of offshore bidding zones.

Viability

Is commercial investment in generation capacity viable given the distribution of revenues and risks?

As discussed extensively in section 2.3.4 on the distribution of revenues under the two options and in section 3.2.1 on the modelling results, the Offshore Bidding Zones approach results in lower generator revenues, although the absolute scale of this impact is mitigated by the fact that hybrid projects themselves support price convergence among the connected zones. In the specific scenario we have modelled, and as described in section 3.2.1, aggregate generator revenues are 1–5% higher under the Home Markets option relative to the Offshore Bidding Zones option, with larger variation observed at the project level. In general, this difference in generator revenues will tend to increase the total volume of generation projects that are viable commercial investments under the Home Markets approach, either because less government subsidy is required by hybrid generation projects and available funds are depleted less rapidly, or because additional projects become commercially profitable.

That said, section 2.3.4 shows that, with regulatory reforms, generator revenues could be made equivalent under both the Offshore Bidding Zones and Home Markets options. Generators could, for example, be given the congestion income stream related to their generation and, potentially, be asked instead to contribute to the cost of the associated transmission investment.

Investment viability will also be influenced by revenue uncertainty. Here, it is not obvious that either option is inherently superior and our modelling shows no marked difference in price volatility between the options. Although price formation under the Offshore Bidding Zones approach is dependent on developments in more markets, which complicates pricing dynamics, these dynamics may also give rise to certain diversification benefits, since future price developments are not hostage to local developments in the home market. Similarly, and as noted separately in section 4.3.1 on the stability of the investment environment, the Home Markets option may face its own sources of price risk stemming from the regulatory risk associated with adopting a less robust long-term regulatory framework. Overall therefore, it is not obvious that either approach is likely to give rise to greater revenue certainty.

[33] As discussed on page 47, where the generator's output must be flowed to a lower-price market (e.g. using countertrade) due to a lack of transmission between the offshore generator and its home market, it is conceivable that the generator be made liable for the cost of the countertrade activity, such that the generator effectively faces the lower price for the output that cannot be transmitted to the home market. In this case, the Home Markets option might not fully shield the generator from a lower capture price.

Overall, we conclude that investment in generation as part of a hybrid project is more likely to be viable under the Home Markets option purely as a result of the fact that it is liable to result in higher generator revenues absent efforts to redistribute revenues from transmission to generation owners.

Efficiency

When considering the efficiency of investment, it is useful to distinguish between providing efficient signals for marginal investment decisions and enabling economically efficient investment by multiple investors.

It is also important to note that the real-world importance of the efficiency of investment signals will depend on the extent to which investment decisions are market driven. It may not matter, for example, if commercial investment incentives for interconnection investments are wrong if these investments are not made on a commercial basis, but rather on the basis of a detailed assessment on the socio-economic welfare impacts.

As discussed in section 2.3.4, restrictions on the redistribution of congestion incomes have the potential to frustrate economically efficient investment by multiple investors. This problem is likely to be more severe under the Offshore Bidding Zones approach, since more of the economic value of the hybrid project is distributed in the form of congestion income. Options to address this problem exist, but probably require further regulatory changes.

On the other hand, the Offshore Bidding Zones approach ensures that the power price at the hub accurately reflects the marginal value of power. As such, it provides efficient signals for marginal decisions on generation and consumption at the hub, as well as for investments in interconnection and storage. In contrast, the Home Markets approach does not.

Consider, for example, the case of a developer wondering whether to add a further wind farm at a hub where almost all of the transmission capacity to the high-price home market is already being used to transmit power from existing offshore generation capacity. In this example, under the Home Markets option, the developer will base the investment decision on the relatively high price available in the home market, but the resultant generation from this additional wind farm will largely end up displacing lower cost generation in other markets. In contrast, the Offshore Bidding Zones option would reflect the true marginal cost of this displaced generation and thereby encourage more efficient marginal decision making and therefore more efficient incremental changes to the offshore network.

Similarly, consider adding additional interconnector capacity from a low-price market to this hub. Exporting more power to this hub can be assumed to result in the hub decoupling from the high-priced home market, due to the limited residual capacity between the hub and the home market. Under the Offshore Bidding Zones option, an investor would be forced to account for this fact, since the price of the hub can be expected to drop and the value of any congestion income will be reduced as a result. However, under the Home Markets option, a merchant investor could hope to capture the full spread between the low-price export market and the home market, even though the hub won't subsequently be able to export all the power to the home market.

Investment signals for offshore energy storage will be similarly distorted. Under the Offshore Bidding Zones approach, the price at the hub will efficiently signal the potential value of storing or releasing power, thereby supporting efficient dispatch and accurately reflecting the economic value of any investment. This will not be the case under the Home Markets option. For example, if offshore generation is locked in, the price under the Offshore Bidding Zones approach will fall to highlight the significant value of storage and encourage investment. Under the Home Markets option, there is no price response and any incentive to investment would have to come from outside the energy market.

In short, the Home Markets option does not give efficient price and investment signals.

Overall, the Offshore Bidding Zone approach results in the efficient price signal but, in the absence of measures to facilitate the redistribution of congestion incomes, may frustrate investment in economically efficient projects. The Home Markets option provides the opposite result. Neither option is therefore unambiguously superior in terms of its impact on overall investment efficiency.

Support schemes

Are efficient national support systems feasible under the option?

National support schemes are feasible under either option. In general, the Home Markets option implies a setup for offshore generators in hybrid projects that is more similar to direct-to-shore connections, like those currently supported. This is likely to make it comparatively easy to support hybrid projects through existing national support mechanisms. In comparison, the Offshore Bidding Zones option is more likely to require additional reforms to existing support schemes in order to enable efficient support of hybrid projects, but the total extent of these reforms may be quite limited in a system in which hybrid and direct-to-shore projects do not compete head-to-head for support.

There are broadly three problems that the choice of market design may pose for national support schemes. The first is the possible introduction of new separate market prices as a result of the creation of new bidding zones. This implies that generators may actually be exposed to a different market price than the one anticipated by existing national support schemes. The second challenge concerns potential national requirements on the perceived location of consumption. The third, which extends beyond the choice of bidding zone design, is the extent to which generation projects may be inconsistently liable for network costs depending on whether they are part of a hybrid project or connected directly to shore.

On the first of these problems, existing Contracts for Difference and flexible Feed-in Tariff regimes will be built around paying out differences relevant to a specific existing market price, on the assumption that generators will be facing this price in the market. The addition of new bidding zones under the Offshore Bidding Zones option implies the need to alter these support mechanisms to allow for the possibility that the generator is facing a different market price. This is not likely to be a terribly complicated change, but is not entirely trivial, since competitive auctions may need to be adapted to meaningfully pick between projects facing different market prices, for example by clearing auctions on the basis of estimated total subsidy costs rather than a consistent strike price.

The second issue concerns national perceptions on the extent to which subsidies support power consumed within the country. Arguably, offshore generators located in offshore bidding zones are more susceptible to perceptions that national funds are being used support renewable power consumed elsewhere. Ultimately, political support for national public subsidy will be strongest where there are clear associated national benefits, for example in terms of supported jobs or a contribution to national targets. These benefits may exist regardless of the market design and therefore support a political case for national subsidy. However, to the extent that offshore generation feeds into an offshore zone that exports considerable volumes of power to other countries or else feeds directly into a multinational offshore zone, the perception of national benefit may be weakened. Even where such perceptions are not supported by sound logic, they may nevertheless weaken the political appetite to use public or consumers' money to support hybrid projects.

The third problem concerns whether hybrid generation projects and generation projects with direct-to-shore connections contribute to transmission costs on an equivalent basis and thereby whether there exists a level playing field among such projects when competing for support as part of a common scheme. If these projects are not facing transmission costs on an equivalent basis, for example because they reimburse transmission owners in different ways, then competitive auctions for support that cover both types of projects are liable to systematically prefer one type of project. As a result, support is unlikely to be awarded on an efficient basis.

Here, the details of the national setup are critical and so it's hard to be definitive. However, in general, generators' contributions to transmission system costs are more likely to be equivalent between hybrid and direct-connection projects under the Home Markets setup. This is because the offshore connection to the home market is effectively part of the internal transmission network under the Home Markets option, as it would be under a direct-connection setup. The generator is therefore more likely to contribute to the costs of building and maintaining the internal bidding zone's network infrastructure through cost-reflective network connection and use-of-system charges. In contrast, under the Offshore Bidding Zones option, all lines to shore are potentially cross-zonal interconnectors and so more likely to be reimbursed with congestion incomes. In the Offshore Bidding Zones case, the generator is more likely to pay indirectly for transmission access to the shore based on the price spread between the hub and the home market, i.e. through the associated congestion income. This spread reflects the economic value of these transmission assets, rather than the transmission owner's costs. This means that, under the Offshore Bidding Zones option, there is more likely to be a systematic difference in the way generation projects are exposed to the costs of providing network infrastructure, a difference that might potentially skew the efficient allocation of support.

It is worth noting that all of these issues could be potentially addressed, at least in part, outside of the support system through bilateral contracting between generation and transmission owners (for example through the use of Contracts for Difference as discussed on page 29). Such contracts could, in theory at least, redistribute revenues and risks among these parties such that generators participating in hybrid projects face costs and revenues that are effectively equivalent to those of a generator with a direct-to-shore connection. Specifically, these contracts could ensure that the generator faces the onshore power price and that it is liable to pay a consistent set of transmission costs.

As the transmission and generation asset owners would remain legally distinct bodies under such contracts with independent ownership of their respective assets and no transfer of control over investment and operational decisions between the parties, the approach should be fully consistent with unbundling requirements. However, as noted previously, regulatory changes are likely required to enable such a redistribution of incomes.

It is also worth noting that, while amendments to existing schemes might be required to support the creation of new zones under the Offshore Bidding Zones options, support schemes are anyway likely to be amended to, for example, support auction-based allocation or to account for the removal of priority dispatch. Incorporating the required modifications as part of such periodic updates would imply relatively little additional cost or disruption.

Finally, note that since generator revenues tend to be higher under the Home Markets option, aggregate generation support costs could potentially be lower. However, since higher revenues for generators come at the expense of transmission owners, this might imply offsetting increases in network charges.

Overall, while effective support schemes can be developed under both options, the Home Markets option's similarity to the status quo is expected to allow existing support mechanisms to be used to support hybrid generation projects with comparatively minor amendments. The extent to which the two options are similar will depend on the specifics of the support scheme design and, where hybrid and direct-to-shore projects are unlikely to compete head-to-head for the same support, the differences between the market designs is likely to be relatively small.

4.3.3 Network

In this section we consider the viability and efficiency of investments in transmission infrastructure. The focus of the discussion is on commercial network investments, since such investments will be materially affected by the choice of market design. However, it is important to note that much transmission investment can be expected to be driven by national regulatory frameworks and may therefore be less affected by the specific choice of market design.

Viability

Is commercial investment in transmission capacity viable given the distribution of revenues and risks?

It is worth noting at the outset that much investment in transmission capacity is not currently made on a fully commercial or merchant basis, as discussed further below. However, to the extent that commercial investment in transmission capacity is relevant, the effect of the market design options on the viability of commercial network investments mirrors that of commercial generation investment viability discussed above.

Specifically, the Offshore Bidding Zones option implies that larger revenues are captured by transmission owners through congestion incomes. Other things being equal, this should support the greater viability of commercial transmission investments under the Offshore Bidding Zones option. The largest beneficiary of this change is the owner of the transmission asset within the would-be home market, as this asset can now earn a congestion income, something that would not be possible where this asset forms part of the internal transmission network of the home bidding zone.

As before, the actual distribution of revenues would depend on the presence of any additional mechanisms intended to redistribute revenues between generation and transmission owners. Note, however, that allowing generators to keep congestion incomes associated with congestion between their offshore bidding zone and a high-price market should not result in a situation in which the generators are net financial beneficiaries from the continuation of this congestion, as any increase in congestion incomes is offset by lower wholesale market revenues.

For a regulated TSO, the decision to invest in transmission capacity will normally be subject to a regulatory assessment of the costs and benefits of the transmission investment by the National Regulatory Authority. This assessment will likely include a consideration of both congestion income and generator revenues or, more accurately, producer surplus. Since the choice of bidding zone design principally affects the distribution of these revenues and such regulatory assessments generally account for both congestion incomes and producer surplus, their conclusions are less likely to be affected by the market design. Put simply, higher gains in congestion incomes under the Offshore Bidding Zones approach will be netted out against losses in producer surplus and vice versa, leaving the net cost or benefit picture largely unchanged.

Overall therefore, we conclude that the higher congestion incomes earned under the Home Markets option should support the viability of commercial / merchant investment in transmission capacity, but that any impact on TSOs' investments is unlikely to be significant.

Efficiency

Are network revenues likely to provide efficient investment incentives?

Again, the arguments related to the efficiency of commercial transmission investment are identical to those discussed above in relation to the efficiency of generation investment. Specifically, the Offshore Bidding Zones option may hamper commercial investments in even economically efficient hybrid projects but does provide efficient price signals for marginal investment decisions.

As alluded to above, transmission investments are unlikely to be taken based on the commercial price signals alone, and consequently, the inefficiency of the price signal under the Home Markets approach may have little impact on the overall efficiency of transmission investment. To appreciate this, let us consider two likely consequences of the Home Markets option.

The first is that transmission assets between the hub and home market will receive no congestion income even where the line is fully congested and additional capacity would increase welfare. This absence of congestion income is clearly not an efficient market signal and could conceivably result in under-investment, but inevitably there must exist alternative mechanisms to encourage TSOs to invest in efficient internal reinforcements that resolve internal congestions within their networks. This issue is in no way special to hybrid projects.

Similarly, the Home Markets option is also likely to result in a price spread and hence congestion incomes on transmission assets that are not congested. While this price spread might trigger consideration of increasing transfer capacity over the uncongested line, any superficial analysis of the investment case will discover that adding transmission capacity is unlikely to increase flows or increase social welfare. Consequently, while the price signals given to transmission owners may be wrong under the Home Markets option, it seems unlikely that they will, by themselves, trigger inefficient investments.

Again, we conclude that neither option is unambiguously superior in terms of its impact on overall commercial investment efficiency. In realty, the overall efficiency of such investments is far more likely to be driven by the regulatory framework underpinning such investments than by the market design.

4.3.4 P2X

In this section we consider specifically the connection of loads, notably electrolysis, offshore at the hub. We are aware that some consideration has been made of extending offshore bidding zones to onshore industrial sites at the landing point. Our definition of the Offshore Bidding Zones option implies that these offshore zones are defined to reflect structural congestion in the transmission network and we assume that, in most cases, the cable to shore will represent the transmission bottleneck.

Viability

Is investment in P2X capacity viable given the distribution of revenues and risks?

As discussed in section 3.2.6, it is not clear that P2X investment linked to the development of hybrid projects is rational under the Home Markets option since the market design provides the P2X developer with no incentive to try to and co-locate with offshore generation. Offshore Bidding Zones open up the possibility of comparatively favourable power pricing within the relevant bidding zone, even where part of the 'offshore' bidding zone is onshore. This is particularly true where offshore generation is partly locked in, as the P2X producer may then purchase any locked in power at a price below that in neighbouring markets. Favourable prices within the offshore bidding zone might also result due to a tendency for the offshore bidding zone price to couple alternately with different low-price markets, thereby keeping average prices in the offshore bidding zone below those of neighbouring bidding zones.

Efficiency

Are P2X revenues likely to provide efficient investment incentives?

Here we consider the case of adding a load to an existing hybrid project hub. As noted in the other sections on the efficiency of investment above, under the Offshore Bidding Zones option, the price at the hub reflects the marginal costs of supplying power there.

This option therefore provides the most efficient price signal for the consideration of marginal investments at the hub.[34]

4.4 Balancing and Congestion Management

In this section we consider the likely efficiency of balancing and congestion management, whether the market design is likely to support greater flexibility in the power system and what impact the options will have on the overall level of curtailment offshore.

4.4.1 Efficiency

Will balancing and congestion management be efficient?

Both market arrangements have their own challenges with respect to balancing and congestion management, as described in detail in sections 2.2.3 and 2.3.3.

The Home Markets approach implies that information on the transmission capacity limits between the offshore generator and the Home Market are effectively hidden from the market. During the intraday market timeframe, this means that the system operator may need to react to offshore generators' intraday trades by conducting countertrades to relieve congestion or by adjusting cross-zonal capacity limits to reflect newly available trade capacities. Having looked at various possible 'fixes' to this issue, it seems unlikely that the fundamental challenge can be eliminated without significant effort. While the system operator's follow-up actions could theoretically ensure the efficiency of the dispatch solution, the need for the system operator to proactively correct the market solution in this way opens up the possibility for the generator and system operator to act in an uncoordinated manner that harms efficiency. For example, if the offshore generator buys power intraday that effectively opens up additional spare cross-zonal capacity, the system operator will be responsible for identifying this change and releasing the capacity to the intraday market. Any lag before this capacity is released to the market (assuming it is released at all) may result in this capacity being used less efficiently.

In terms of imbalance settlement, in the same way that including the offshore generator in the onshore price zone can result in market prices that give inefficient dispatch signals, imposing the same imbalance settlement price on the offshore generator as that applied to the rest of the home market may give an inaccurate price signal on the true cost of imbalance. For example, an offshore generator might receive an imbalance price for excess power that reflects prices in the high-priced home market even where this additional power actually displaces low-cost power from a foreign export market. Such inaccurate price signals can also impose an efficiency cost, since the generator has inappropriate incentives to manage its own imbalance position.

The Offshore Bidding Zones option makes things significantly easier in the intraday timeframe, as transmission constraints can be reflected directly in the market coupling arrangements. This reduces the scope for congestion issues that the system operator must fix.

After gate closure, the Offshore Bidding Zones approach allows for the possibility that offshore generators will face a cost-reflective imbalance price, but implies the need for strong cross-zonal coordination to ensure the efficiency of balancing actions. However, measures are already in place to enable cross-zonal trade in balancing services and strong coordination could be fostered by the direct involvement of the onshore system operators in balancing the offshore system. As such, these challenges seem eminently solvable.

[34] For non-marginal investments where the investments' impact on the zonal price might potentially distort investment incentives, particularly in a small offshore price zone, bilateral Power Purchasing Agreements or co-ownership with generation in the zone should still allow for socially efficient investment outcomes under the Offshore Bidding Zones option.

Overall therefore, the Home Markets option seems most likely to give rise to inefficiencies related to balancing and congestion management. Specifically, it requires the system operator to proactively manage congestion on the hybrid project intraday, opening up the possibility that such corrections are inefficient. It is also likely to imply that offshore generators face the same imbalance settlement price as the home market, which may not accurately reflect the cost of imbalances offshore and therefore fail to incentivise efficient self-balancing.

4.4.2 Support for flexibility

Will the arrangements enable the use of flexibility to support integration of variable generation?

It is useful to consider separately the options' effects on the use of flexibility onshore and on the incentives to provide flexibility offshore.

Thinking about the use of onshore flexibility first, we note that it will probably be efficient to use onshore flexibility to support variable offshore generation in all cases and both market arrangements are likely to make this possible. Under the Home Markets approach, it is natural to assume that the home market system operator will take responsibility for operating the relevant home market-elements of the hybrid project and the implied presence of a single system operator should help to ensure that onshore flexibility (at least in the home market) can be used to support offshore renewables integration. The Offshore Bidding Zone option does not preclude a similar arrangement, in which an onshore system operator takes responsibility for the offshore zone and, even where this is not the case, TSO-TSO trade in balancing services should ensure that onshore flexibility can support offshore renewable integration under this option. As such, there is not much difference between the options in terms of their ability to access onshore flexibility.

Turning to the incentives for flexibility offshore, we conclude that the ability of the offshore price to signal the value of congestion management directly to the market under the Offshore Bidding Zone option is likely to encourage the provision of offshore flexibility. For example, consider the case of an offshore price zone linking three markets where the price oscillates between that of two connected onshore price zones in which prices are constant. The change in price offshore in this case would be the result of changing offshore generation and congestion. In this case, the intertemporal variation in the offshore price might incentivise the use of offshore storage to help make more efficient use of the available transmission capacity. If the offshore hub were instead linked to one of the onshore areas under a Home Markets arrangement, this oscillation in prices would disappear. The economic incentives for storage in the Home Markets case might be provided through alternative means, e.g. via a contract with the system operator to support congestion management. However, in general, we consider that the presence of a market price signal, as provided by the Offshore Bidding Zones option, is likely to provide a clearer and more robust basis for investment in offshore sources of flexibility.

Overall, we conclude that the Offshore Bidding Zones approach is likely to better support the provision of flexibility services needed for renewables integration owing to its ability to better signal the value offshore flexibility that can support congestion management. However, the difference in the approaches is expected to be limited to a small number of cases.

4.4.3 Curtailment

Will the arrangements limit curtailment?

In this section we consider the overall magnitude of curtailment rather that the efficiency of dispatch, balancing and congestion management, which are dealt with elsewhere. We consider curtailment resulting both from actions by the system operator to reduce generation, as well as curtailment undertaken by the generator itself (so-called self-curtailment) due to very low energy prices. Given this scope, there are several potential reasons for the curtailment of offshore hybrid wind generation and some of this curtailment may be fully efficient. Specifically, curtailment may arise due to:

1. the inability to prioritise internal flows over cross-zonal flows (see section 2.2.1);
2. the desire to prioritise imports of negative cost power (see section 4.2.1);
3. the inability to evacuate wind against a price differential (see section 4.2.1);
4. the inability of the system operator to utilise alternative congestion management solutions; and,
5. the desire of the offshore generator to avoid receiving a negative power price.

The first of these represents a fundamental challenge to the Home Markets design but, critically, is completely eliminated by an assumed legislative change to the Electricity Regulation that enables prioritisation of offshore injections over cross-zonal flows.[35] Were it not for this assumption, this would likely prove the most important of the above sources of curtailment. Given this assumption however, it is not a factor.

The second source, related to imports of negative cost power, reflects efficient curtailment, but only occurs under the Offshore Bidding Zones approach. The assumed prioritisation of offshore injections under the Home Market options removes this efficient curtailment.

The third source of curtailment would only result under the Home Markets approach and would be restricted to circumstances in which wind generation was so large relative to transmission capacity that its evacuation required the power to flow against a price differential. As discussed on p.47, the market dispatch solution will be infeasible in these cases, requiring the system operator to alter dispatch to relieve network congestion. The most efficient response will likely involve flowing power against the price differential, for example through the use of countertrades. However, such activity imposes a real cost on the system operator. As a result, the system operator might alternatively opt to simply curtail the wind output that cannot be evacuated into the home market.

The fourth directly reflects the system operator's success in identifying alternative means to manage offshore congestion. In general, the Offshore Bidding Zone approach implies that congestion problems are handled more effectively as part of the market clearing solution, since the available transmission capacity is represented by an additional border in the market clearing algorithm. The approach is also likely to provide more accurate imbalance pricing. These factors should imply that there is less need for the system operator to undertake congestion management close to real-time. Down regulation in those markets exporting to the offshore hub is the natural alternative to curtailment and it is not obvious that either option is likely to be superior in sourcing these.

The fifth source reflects self-curtailment by the offshore generator. This might occur, for example, because the home market has negative prices and the offshore generator therefore wishes to reduce its output and the costs associated power supply. It is possible for a hub to receive a negative price under the Home Market design, but a positive price under the Offshore Bidding Zones approach. This will ultimately depend on the network topology. Self-curtailment might also occur because of negative imbalance prices for energy, which might be more likely under the Offshore Bidding Zones approach.

Overall, where prices for energy are positive, the Offshore Bidding Zones approach appears to be slightly less likely to induce a need for curtailment, because it reduces the

[35] See the discussion of new priority access on p.11 for further detail on the extent of the legal and regulatory challenge involved in implementing such priority access.

need for the system operator to manage offshore congestion and therefore the likelihood that it will opt to curtail wind. With negative prices in connected zones, the curtailment impacts become more complicated and there is an increased risk that offshore wind is curtailed under the Offshore Bidding Zone approach to enable the efficient import of negative price power. If we remain agnostic on the structure of future power prices, neither option can defiantly be said to result in lower absolute curtailment of offshore wind and we conclude that neither option is obviously superior. However, it is worth noting that the additional curtailment implied by the Offshore Bidding Zones option is efficient, whereas the additional curtailment under the Home Markets option is not.

4.5 Regulatory Compliance

Is the option consistent with existing European regulation?

There are two main issues related to regulatory compliance. The first concerns the inability to prioritise internal offshore injections over cross-zonal flows under the Home Markets option and is discussed extensively in section 2.2.1. The second concerns the distribution of hybrid project revenue under the Offshore Bidding Zones option and is covered in section 2.3.4.

As noted previously, if we were unable to prioritise internal offshore wind injections over cross-zonal flows under the Home Markets option, this would likely significantly impair dispatch efficiency under this option. Consequently, we have assumed that the granting of priority access for offshore injections is an integral part of the Home Markets option. This assumption implies an important break with the existing regulatory model. Although the current regulatory arrangements do allow for some examples of the priority dispatch of generators, Article 12(7) of Regulation (EU) 2019/943 states explicitly that "Priority dispatch […] shall not be used as a justification for curtailment of cross-zonal capacities beyond what is provided for in Article 16". In other words, even in those limited cases in which generators are granted priority dispatch, this priority does not imply prioritisation ahead of cross-zonal flows, which is exactly what is required and assumed under the Home Markets option. In short, as part of this option, we are assuming the creation of a new status of priority dispatch that would be exclusive to these offshore generators and sufficient to overrule the long-standing regulatory principle that cross-zonal capacity should not be curtailed to resolve internal congestion within a bidding zone. In doing so, the Home Markets option may not be compatible with Article 102 of the Treaty on the Functioning of the European Union, as it arguably unfairly discriminates between network users.[36]

Under the Offshore Bidding Zones option, the need for regulatory reform is less pressing but still present. The crux of the problem is that Article 19 of Regulation (EU) 2019/943 restricts investors ability to redistribute congestion incomes among themselves, potentially resulting in a situation in which generators cannot recover their costs even though the hybrid project as a whole is profitable. The immediate problem could be resolved by channelling additional support payments to generators, but implies the need for ongoing public support and may cannibalise limited support funds that could otherwise have been used to support additional deployment. Possible regulatory solutions to the issue are considered in section 2.3.4, however the most obvious and limited regulatory adjustment would imply a relaxation of the restrictions on the use of congestion income for hybrid projects. Time limited exemptions for merchant cables are already available, as set out in Article 63 of the same regulation. As such, this regulatory change is considered to be less fundamental than that required by the Home Markets approach.

Overall, the Home Markets approach appears to entail the need for a fairly significant break from current regulatory principles in order to avoid either a potentially significant source of dispatch inefficiency or else the need to restrict offshore generation capacity

[36] This issue has been previously considered as part of legal proceedings involving TenneT and Svenska Kraftnät.

relative to cable size. In contrast, the Offshore Bidding Zones approach does not require regulatory changes, although some reforms, notably in relation to the restrictions on congestion income, would be useful to alleviate the need for support schemes.

4.6 Cross-Zonal Hedging

To what extent is long-term cross-zonal hedging feasible?

When considering cross-zonal hedging, it is useful to distinguish between hedging across the zonal borders that would be present under both options and hedging across the border with the home market under the Offshore Bidding Zones option.

Regarding the borders present under both options, there is unlikely to be any significance difference in the feasibility of hedging opportunities. The only slight difference relates to the additional difficulty in calculating available cross-zonal capacity on these borders under the Home Markets option, as discussed in 2.2.2. Potentially this additional challenge might result in a lower volume of Financial Transmission Rights being made available on the affected connections, but any impact would be expected to be minimal.

The real difference between the options relates to the border with the home market. Under the Home Markets design, this border is removed as part of the market design and consequently there exists, in effect, a perfect hedge built-in to the market arrangements themselves and subject only to the risk of subsequent bidding zone changes.

The nature of the hedge available under the Offshore Bidding Zones option is interlinked with the issue of revenue redistribution discussed in section 2.3.4, since the options for sharing income between transmission and generation asset owners directly affects their risk exposure. Some options, like a bilateral Contract for Differences tied to the generator's output, would provide generators with a perfect hedge, indeed one that was arguably superior to that of the Home Markets option since it is robust to later bidding zone reform. Others, like the use of Financial Transmission Rights, would be inferior to the hedge provided by the Home Markets option but equivalent to the hedging options available on any other border.

Overall, we conclude that, although the quality of cross-zonal hedging is an important consideration in assessing alternative models of revenue redistribution under the Offshore Bidding Zones option, cross-zonal hedging is likely to be feasible under both the Home Markets and Offshore Bidding Zones options and unlikely to be inherently superior under either option.

4.7 Political Acceptability

In this section, we consider to what extent the options imply the need for supranational governance and the ease with which they could support a variety of different options for cost sharing arrangements and different national regulatory models. Critically, we also consider the extent to which the options avoid discrimination among different market actors.

4.7.1 Subsidiarity

To what extent does the option avoid a transfer of power to a supranational level?

Neither the Home Markets nor the Offshore Bidding Zones option imply a transfer of power to a supranational level. In both cases, system operation could be managed by an existing national system operator or through multilateral cooperation among existing system operators. Offshore bidding zones could well existing entirely within national boundaries and be governed by existing governance arrangements. Similarly, both the Home Markets and the Offshore Bidding Zones option could involve the creation of bidding zones that encompass generators in multiple countries. Such bidding zones already exist, e.g. the Integrated Single Electricity Market in Ireland, and can be managed mutually by the countries involved. As such, both models are deemed to perform equally against this criterion.

4.7.2 National flexibility

To what extent does the option provide flexibility in the sharing of costs or in the choice of a national regulatory model (e.g. related to interconnection, TSO regulation or renewables support)?

In general, the options are fairly permissive in terms of their compatibility with alternative project development processes and support mechanisms, although they may impose some limitations on likely transmission ownership and cost sharing arrangements.

Both options could reasonably support hybrid projects developed either through public tenders for specific projects or identified through developer-led processes. Similarly, both are amenable to a variety of possible national support scheme arrangements, although as noted in section 4.3.2, existing support schemes would likely have to undergo some modification if they were to be applied to projects in new offshore bidding zones.

Regarding their applicability to alternative potential ownership models for the transmission assets, it's worth noting that the Home Markets option is likely to fit more naturally with a framework that assumes TSO-based ownership, or OFTO regulation, than one that is hoping to use merchant interconnectors. Most obviously, the Home Markets option ensures that no congestion income could be earned on the transmission link between the hub and the Home Market, precluding this from being a commercially viable merchant project. In addition, the Home Markets option risks distorting the congestion incomes earned on the other transmission connections, for example by awarding a congestion income to cables that are uncongested. Assuming a high-price home market, for example, the owners of this uncongested cable would earn additional revenues under the Home Markets option at the expense of the home market TSO and, indirectly, its users.

Finally, as noted previously, a greater share of the economic value of hybrid projects is dispersed as congestion incomes under the Offshore Bidding Zones option. The regulatory limitations on the use of these incomes limit flexibility in terms of the sharing of costs. This has already been discussed extensively as regards the distribution of revenues between transmission and generation, but these limitations may also complicate the flexible distribution of value internationally for projects where, for example, a regulator expects some of this value to be shared with the consumers of the other countries involved, rather than just those who are customers of the TSO owning a congested line.

In conclusion therefore, neither option is clearly superior in terms of its ability to accommodate a more diverse variety of national arrangements. Both options could be applied in a variety of national contexts.

4.7.3 Discrimination

To what extent does the option avoid undue discrimination between different market actors? (Level playing field)

Providing priority access to offshore injections under the Home Markets option may be necessary to avoid the inefficient curtailment of offshore generation. However, this prioritisation may result in undue discrimination between market participants.

Most obviously, priority access implies that offshore injections are prioritised above cross-zonal flows. This is, of course, the intention. However, if this priority applies even where power is being offered in a connected zone at negative prices, as we have assumed, the market arrangements are arguably discriminatory. In this case, generators in the negative price zone are having their offers rejected, despite their willingness to sell power at a negative price, in order to provide network capacity to an offshore generator that is offering power at a higher price.

Priority access for offshore injections could also conceivably lead to discrimination among generators within the Home Market. Take for example a case in which power is being exported from the home market along the hybrid asset to a neighbouring market. The priority access given to the offshore wind farm means that it would be dispatched ahead of an identical onshore generator in order to fulfil the export demand. Admittedly, with an assumed offer price of zero, the home market price would also have to be zero in the event that only one of the two plants were dispatched, but this could potentially make a difference to the plants' entitlement to support payments.

Overall, therefore, the assumed implementation of priority access for offshore injections under the Home Market option can be argued to give rise to undue discrimination among market participants.

4.8 System Security

In this section we consider the options' impacts on the security of system operation and on the certainty provided to system operators regarding available cross-zonal capacity.

4.8.1 Operational security

To what extent does the option support operational security and/or generation adequacy?

There are broadly two mechanisms by which the choice of market arrangements might influence operational security: the extent to which the arrangements encourage dispatch and consumption decisions that might impair operational security and the extent to which the arrangements furnish the system operator with the tools necessary to resolve potential problems.

On the first of these, the Home Markets solution is more likely to induce dispatch and consumption behaviour that threatens operational security because it effectively hides the transmission constraint between the offshore hub and the rest of the home market from the market trading arrangements. As discussed previously in section 4.4.1 on the efficiency of balancing and congestion management, this results in two potential problems. First, intraday trade risks inducing dispatch behaviour that is infeasible given this transmission constraint and implies the need for the system operator to continuously amend the market solution, for example through countertrade. Second, the imbalance price at the offshore hub will fail to reflect the costs of imbalance at that point, such that an offshore generator may be content to spill any excess power into imbalance even through the value of this power is significantly below that implied by the imbalance price or even negative. For both these reasons, the Home Markets approach is clearly inferior in terms of its ability to produce secure dispatch behaviour.

Regarding the availability of services that can be used by the system operator, we conclude that there is no significant difference between the options. Although it is natural to assume that under the Home Markets option a single system operator would be responsible for operational security both on- and offshore and would therefore be able to utilise the existing services available to it in managing operational security offshore, a single system operator could also be used as part of the Offshore Bidding Zones option. In either case, this system operator is likely to want to call on balancing services in other connected onshore zones and, here, TSO-TSO coordination and trade in balancing services will be required regardless of the overall market design option being considered.

Overall, we conclude that the Offshore Bidding Zones approach is likely to better support operational security by reflecting transmission constraints between the offshore generator and the shore in both the market and imbalance settlement price. This promotes dispatch behaviour more consistent with the physical limitations of the system.

4.8.2 Certainty over Cross-Zonal Capacity

To what extent does the option give TSOs' certainty over available cross-zonal capacity?

The different options imply different zonal definitions and, consequently, the volumes covered by cross-zonal capacity also differ by option. If we consider the capacity available for cross-zonal trade, which system operators must report to the market in advance of the day-ahead market, it is clear that this quantity is far more certain under the Offshore Bidding Zones option. As explained in section 2.2.2, the estimation of this capacity is complicated under the Home Markets option because available cross-zonal capacity becomes dependent on uncertain offshore wind injections.

If we instead consider the availability of spare transmission capacity between the offshore hub and the home market, which technically ceases to be cross-zonal capacity under the Home Markets option, this too is likely to be more certain under the Offshore Bidding Zones option. During the period when the market is open, this is because the offshore generator does not have priority access under the Offshore Bidding Zones option and, as result, market flows are constrained by the limits specified in advance by the system operator. The Offshore Bidding Zones option is also likely to provide more explicit signals as to the state of available capacity, with scarce capacity clearly signalled by price splitting between the zones. Congestion on this line is less conspicuous under the Home Markets design. After the market closes, certainty regarding flows is also likely to be supported by a more cost-reflective imbalance settlement price at the offshore hub under the Offshore Bidding Zones option, as noted above, which can be expected to supported better incentives for real-time balancing on the part of generators and loads at the hub.

Overall therefore, for all these potential quantities of interest, the Offshore Bidding Zones option is likely to support greater certainty and transparency.

4.9 Scalability and Adaptability

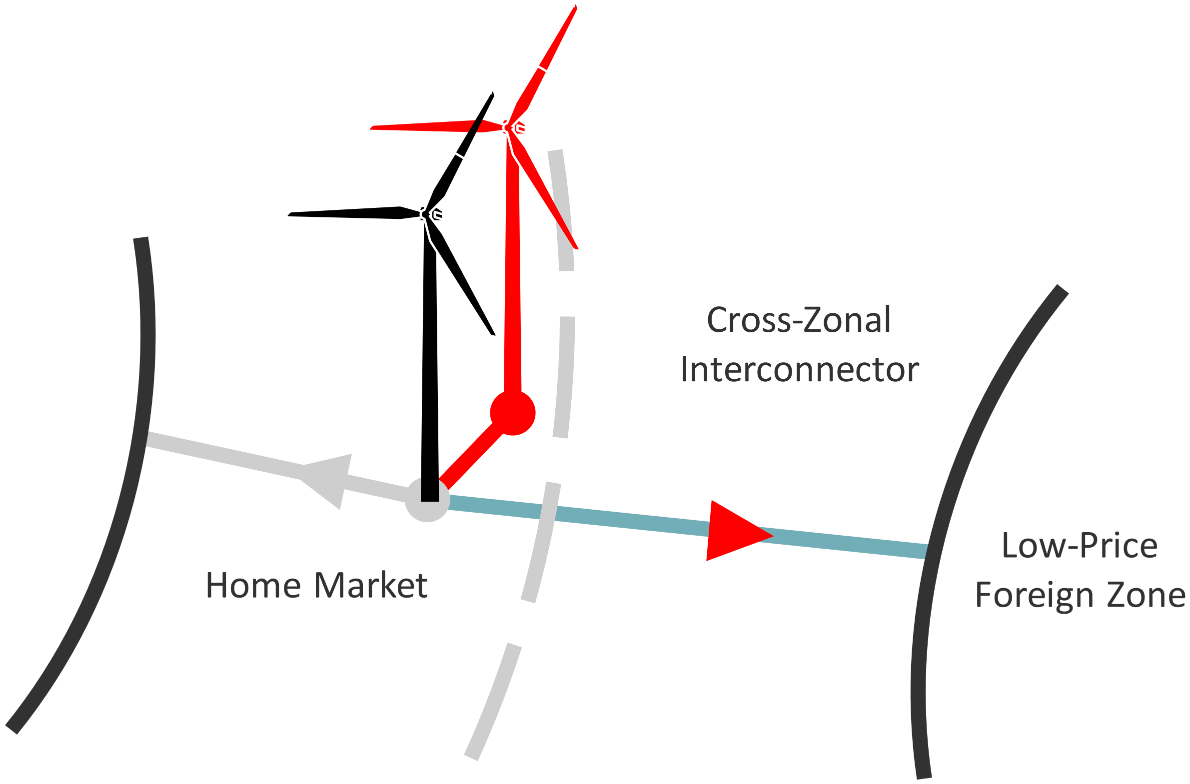
In this section we consider the extent to which the market design can adapt to the gradual modification of the offshore network and enable anticipatory investments. We also whether it will be fit-for-purpose in a future in which there might be large volumes of offshore generation, complex offshore networks and offshore loads.

4.9.1 Adaptability

To what extent can the option adapt to the gradual expansion and extension of offshore capacity?

The Home Markets approach implies, in effect, a restriction on bidding zone design and pricing behaviour that can be seen to limit its adaptability to changes in offshore assets and structural congestion. To see this, imagine the case depicted in Figure 28 below. Initially, let us assume that the red offshore generator is not present. The initial generator forms a part of the home market and power flows to the home market from both the offshore generator and the low-price foreign zone. Subsequently, offshore generation capacity is expanded through the addition of the red generator and the Home Market design requires that this capacity be included in the home market. However, transmission capacity between the hub and the home market has not been expanded and, as a result, the line from the hub to the low-price foreign zone is increasingly used to evacuate the power generated offshore, rather than to import power into the home market. In this case, we end up with the situation, mentioned in 4.4.3, in which power is actually being flowed against a price differential between two bidding zones, i.e. in which power is flowing from high to low prices.

Figure 28: Example of Adaptability Challenge Under the Home Markets Option



In this example, we have a case in which the initial bidding zone design and market behaviour seems reasonable given the nature of the specific asset configuration. However, over the course of a few decades, the design subsequently becomes deeply problematic as a result of changes to the asset configuration, specifically the addition of more generation capacity at the hub.

In general, the Offshore Bidding Zone case is robust to changes in the pattern of flows and the location of congestion and allows an additional degree of flexibility in responding to these changes through the use of offshore prices. As such it is the more adaptable of the options and can ensure that dispatch remains efficient even if, for example, generation, consumption and transmission investments do not come online in sync.

4.9.2 Anticipatory investment

To what extent does the option facilitate anticipatory investments?

Anticipatory investment entails undertaking investment ahead of need. It may be beneficial where there are significant fixed costs associated with subsequent expansions and these fixed costs can be saved by avoiding the need for follow-up investment. Successfully undertaking anticipatory investment implies an ability to anticipate future needs and, where the party responsible for the investment is different from the party with the future need, the existence of mechanisms through which the investor can recoup the subsequent value of the investment. Examples of potentially relevant investments include the construction of 'oversized' transmission capacity, anticipating its future use by offshore generators.

The key determinants of anticipatory investment relate to long-term energy system planning, the infrastructure investment decision making process of TSOs and network charging arrangements for offshore generators. These factors are not elements of the market design and the impact of the market arrangements on anticipatory investment are likely to be of secondary importance in relation to these other factors. In particular, a TSO with an investment mandate to maximise social welfare, armed with a clear plan for future energy system development and permitted to finance anticipatory investment using onshore tariffs would be able to undertake anticipatory investments irrespective of the market arrangements.

If we assume that the transmission owner needs to be able to recoup the costs of anticipatory investments in transmission capacity through the use of connection charges paid by subsequent generators however, it may be harder to enable such investments under the Offshore Bidding Zones design. Take the specific example of considering oversizing a transmission cable between an offshore hub and its home market in anticipation of additional generation capacity being added later. Under the Home Markets arrangements, it seems reasonable to assume that the relevant TSO could justify imposing a connection charge that accounted for the costs of this oversizing, since the reinforcement forms part of the TSOs own internal network. Under the Offshore Bidding Zones option, the relevant cable is an interconnector and it would seem far less reasonable to charge the connecting generator for earlier interconnector investment even where these transmission assets were, de facto, needed to evacuate the generator’s output.

It is important to note here that this question becomes inextricably tied to the discussion of hybrid project revenue distribution covered in section 2.3.4. In particular, although the transmission owner may no longer be able to reasonably include investment in the cable in a formal connection charge, it could earn additional congestion income. Under an option in which it was possible to give the congestion income to the generator, the transmission owner could reasonably charge for the rights to this income, and this would enable it to recoup the costs of the anticipatory investment. However, the arrangements risk being very case specific and so difficult to implement in practice.

Overall, we conclude that the choice of market arrangements is probably of secondary importance in determining whether or not efficient anticipatory investments occur. This is far more likely to be driven by the effectiveness of the planning system and by national regulators’ approaches to eligible costs. As such, anticipatory investment is potentially possible under either market design. At the margins, the Home Markets arrangements may make it slightly easier for networks to undertake anticipatory investments in transmission infrastructure because it will be easier to recoup the costs of these investment through network charges placed on subsequent generators.

4.9.3 Futureproofing

To what extent is the option future-proofed against large volumes of offshore generation, complex offshore networks and the presence of offshore loads?

The Offshore Bidding Zones option ensures efficient dispatch and marginal investment behaviour even in the context of a complex offshore network and the use of offshore loads. In contrast, the inefficient pricing signals provided by the Home Markets option, as well as the greater need for system operator activity to correct the market solution, are likely to be income increasingly problematic as the scale and complexity of the offshore network grows.

As noted above in section 4.9.1, network flows and structural congestion can change with the addition of new offshore assets. The Home Markets option effectively restricts the ability of the market to reflect and adapt to those changes by requiring that all offshore generators and consumers within the home market be treated identically. One might argue that the adaptation of bidding zones to account for changes over time would continue to be a part of the Home Markets option given, in particular, the process for the review of bidding zone configurations set out in Article 32 of Regulation (EU) 2015/1222. However, if there was a serious threat of the creation of offshore bidding zones under the Home Markets options, this would undermine the chief advantage that this option has in terms of providing investors in offshore generation with reasonable certainty that they will face the power price in the relevant home market. As such, if the Home Markets option is to provide this certainty, it must necessarily accept a certain degree of rigidity in the arrangements and the risk that these arrangements subsequently become ill-suited to the actual configuration of offshore assets.

The Home Markets option is also likely to perform relatively poorly when considering the future needs of a system with offshore load. Here we consider its implications for both consumption and investment efficiency. The Offshore Bidding Zone approach ensures that the price at the offshore hub reflects the marginal value of any additional power consumed, as explained in detail in the price determination example shown earlier in Figure 6. In contrast, the Home Markets option potentially allows the price at the hub to be higher than the marginal value at the hub.

Let us assume, for ease of exposition, that the Home Markets approach implies a price of 30 at the hub, whereas the Offshore Bidding Zones approach implies a price of 20. As noted above, 20 is therefore the marginal cost of power as assessed at the hub. If we imagine a case in which there is a source of load at the hub for which consumption is only economic at prices of 25 or less, then this consumer will not consume in the Home Markets case because of the high price. This consumption decision will be inefficient because the true marginal cost of providing power at the hub is 20. Encouraging the efficiency of consumption decisions at the hub can be seen as especially important because this consumption may be one of a fairly limited number of sources of price-sensitive flexibility at the hub. A failure to use this flexibility efficiently implies the need for the system operator to seek other, more costly, means for managing congestion within the offshore network.

This disconnect between the marginal costs of power consumption at the hub and the power price under the Home Markets approach is also liable to distort investment decisions. Reusing the example above, let us assume that the power price of 20 under the Offshore Bidding Zones option reflects the price of importing power from a connected zone, implying that this is the marginal source of power at the hub. From a power costs perspective, an investor in hydrogen electrolysis capacity, for example, should be indifferent between locating at the hub or in the connected zone with price 20. Let us say, however, that the investor's other costs are slightly lower at the hub. It is therefore preferable for this electrolysis capacity to be sited at the hub. Under the Home Markets option, the investor faces a price at the hub equivalent to the high-price home market even though this is higher than the marginal cost of providing power at the hub. This will distort investment decision making and ultimately lead to investment decisions that are inefficient.

Although these arguments are made in the context of offshore loads, they apply more generally and point to the broader efficiency of offshore bidding zones in dealing with new and possibly unanticipated setups. For example, if we imagine that future offshore generation might be available at higher prices, for example as offshore hydrogen stores are used for offshore generation, this generation will be efficiently dispatched under an Offshore Bidding Zone setup. Under a Home Markets arrangement in which this generation also gets priority network access, it might be inefficiently dispatched in response to high home market prices even where the demand could have been more efficiently met by importing lower cost renewable power from neighbouring markets.

In short, because the Home Markets approach does not support efficient marginal pricing, it is likely to harm welfare by distorting decisions that are informed by the offshore power price. As the number, variety and complexity of these decisions' increases, so too does the likely welfare loss.

Partly as a result, attempting to apply a Home Markets setup to large, complex offshore grid supplied by large volumes of variable offshore generation would imply the need for significant system operator activity to manage this system. Either network development will be inefficiently skewed towards reinforcing connections between farms and their home markets, in an attempt to fit the physical network to the bidding zone structure imposed by the Home Markets design, or system operators will be forced to conduct out-of-market redispatch behaviour to account for the fact that the market does not accurately reflect the limits of the physical power system. In either case, this mismatch is likely to have a real-world cost, either in terms of higher capital costs for the network, or in terms of the costs of system operation. Ultimately, these higher costs could make large scale renewable deployment offshore harder to achieve

In summary therefore, the Offshore Bidding Zones option is more robust to changes in the scale and nature of offshore assets over time and supports more efficient consumption and investment decisions for offshore load and generation. As a result, it is the preferred choice for future-proofing the market design arrangements.

5 CROSS-BORDER GOVERNANCE OF OFFSHORE BIDDING ZONES

Although good governance arrangements will be important to support commercial investment and the secure and efficient operation of the system, the governance issues posed by offshore bidding zones are not unprecedented. Offshore bidding zones that do not cross national borders can be effectively governed using existing national arrangements. For a multinational zone, regulatory governance could be provided for through NRA cooperation, possibly institutionalised in a joint committee. Real-time system operation could be supported through the use of TSO service and cost sharing agreements. In both cases, these arrangements are precedented by the experience of the Irish Single Electricity Market, and we therefore conclude that workable governance arrangements for multinational offshore bidding zones could be established along these lines.

Forming new offshore bidding zones for hybrid projects that potentially cross national borders raises questions about how these zones should be regulated, how system operation will be performed, and how bidding zone borders will be determined. The interplay between different actors in such structures would need to be clearly defined. Effective governance arrangements will be required to avoid uncertainty for investors, offshore operators and networks and these arrangements need to be able to settle potential disputes among stakeholders, and potentially even between national regulators. Many of the potential challenges are not unprecedented and, as such, governance structures already exist to address them. In particular, we note that:

- Several European countries (Norway, Sweden and Italy) already operate with multiple bidding zones intended to reflect structural congestion in the transmission network.
- Multinational bidding zones already exist, notably the Single Electricity Market in Ireland and the Germany-Luxembourg (and formerly Austria-Germany-Luxembourg) zone.
- A European regulatory process for bidding zone determination already exists[37], as does a process for settling disputes between National Regulatory Authorities (NRAs) on cross-border capacity allocation issues.

Consequently, establishing appropriate governance arrangements for offshore bidding zones does not entail solving entirely new problems and, in many cases, can be suitably addressed through the sensible application of existing processes by existing bodies.

In this section, our aim is to try and identify workable models for the governance and operation of offshore bidding zones as a means to demonstrate the feasibility of such zones from a regulatory perspective. In doing so, we have drawn on practical examples of international cooperation.

We consider that workable arrangements will need to allow for effective:

- Regulatory decision making;
- System operation; and
- Bidding zone determination.

The remainder of this chapter considers possible mechanisms to meet each of these needs.

We have not considered in detail the process by which a consensus on the use of offshore bidding zones might be achieved, however, we discuss some relevant considerations alongside the treatment of bidding zone determination below.

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[37] See Chapter 2 of EU Regulation 2015/1222 (Guideline on Capacity Allocation and Congestion Management)

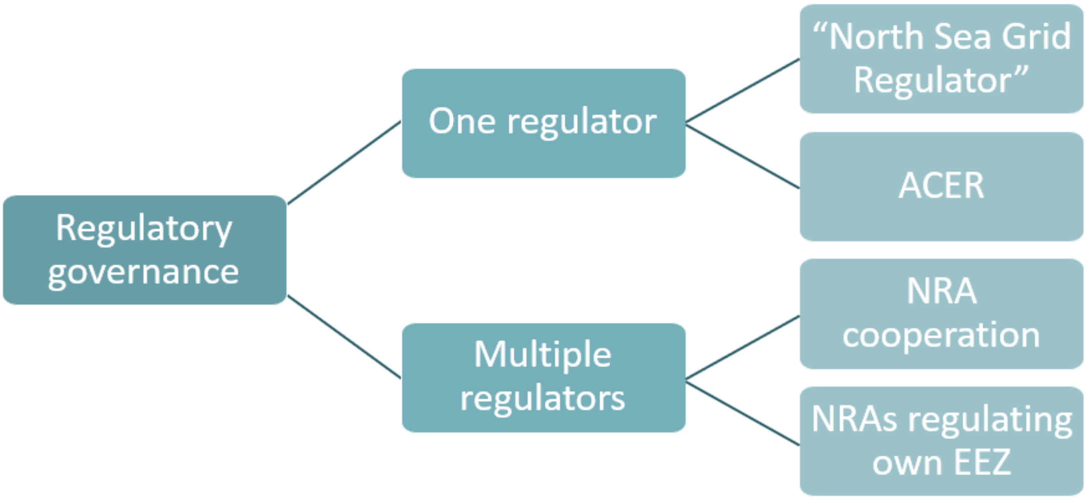
5.1 Regulatory decision making

In this section we consider how offshore bidding zones will be regulated. It is important to note that such zones may exist entirely within a single country's Exclusive Economic Zone. Such bidding zones could be regulated entirely by the relevant NRA and, as such, imply little to no change relative to existing regulatory practice. This section focuses on the more interesting case of an international offshore bidding zone. The greater attention given to this more challenging case does not imply that such international zones would necessarily be the norm or that the existence of multinational zones is a necessary consequence of the use of offshore bidding zones.

With regard to regulatory decision making, the PROMOTioN project[38] has previously explored different possible models for international regulatory cooperation in the context of a meshed offshore network. In addition to considering possible models for regulatory decision making, the PROMOTioN project also reviewed the fundamental need for regulation and noted that, since networks will also be natural monopolies offshore, network regulation is likely to be essential to ensuring efficient and non-discriminatory network development.

The PROMOTioN project presents four models for regulatory decision making arrangements and these are outlined in Figure 29 below.[39]

Figure 29: Governance models for transnational offshore networks



Source: PROMOTioN (2019). Deliverable 7.2: Designing the Target Legal Framework for a Meshed Offshore Grid, Image 3

These models are divided into two centralised approaches and two decentralised approaches. In the centralised approaches, a single international regulatory body is given regulatory responsibility for the international bidding zone. Under the decentralised approaches, which more closely reflect the status quo, regulatory authority remains with the relevant NRAs. The four options considered are:

- North Sea Grid Regulator – Regulatory authority for the bidding zone is given to a new 'North Sea Grid Regulator'.
- ACER – ACER is assigned regulatory authority for the bidding zone, effectively becoming a regulatory authority in its own right for the offshore jurisdiction.
- NRA cooperation – Multiple NRAs have legal authority for different regions within the bidding zone but take collective responsibility for regulatory decisions. These decisions are made with the help of formalised multilateral NRA groups. The structure of these groups and their decision-making practices could be agreed

[38] https://www.promotion-offshore.net/

[39] See PROMOTioN deliverable 7.2.

among the NRAs directly and would not necessarily require new legislation to implement.

- NRAs regulating own EEZ – There is strict adherence to the principle that NRAs have ultimate authority over their EEZ and each NRA decides on any issue that affects its EEZ. Where relevant, all affected NRAs may have to come to consistent decisions or the issue will have to be resolved by ACER.

The PROMOTioN project notes that the latter two decentralised approaches are likely to be easier to implement, especially initially, when developing single hybrid projects. Maintaining a strict separation of NRAs' authority within their own EEZs avoids the need for changes to current legislation and thus represents an easy solution for the development of early projects. However, the study also points out that a strict separation of regulatory authority at the borders of EEZs could lead to more cumbersome governance issues at later stages of offshore network development when more than two countries share an interconnection. That said, they cite the stakeholder experiences in relation to interconnector development as demonstrating that repeated cooperation between NRAs results in improvements in efficiency over time, as the NRAs involved learn how to work more effectively together.

The study suggests that more institutionalised cooperation among NRAs, as under the 'NRA cooperation' option, could alleviate the comparatively high transaction costs associated with strict division of authority at the EEZ border while still not requiring the transfer of authority away from the NRAs. The 'NRA cooperation model' is ultimately identified as the preferred approach, not least since the creation of a North Sea Grid Regulator or else expanding the role of ACER is unlikely to find support, especially at this early stage of offshore development. The PROMOTioN study concludes that the 'NRA cooperation model' is most likely to succeed and proposes that areas such as tariffs, the access regime, safety standards, etc. should be jointly decided upon by the involved regulators. The PROMOTioN study also notes that the regulatory model might naturally evolve from bilateral NRA cooperation to the creation of a centralised regulator if the relevant member states want to enhance the level of cooperation and centralised coordination at a later stage.

As noted previously, international bidding zones are not unprecedented and discussions with the Austrian and German NRAs confirm that informal cooperation between the NRAs worked well in allowing for coordination and cooperative decision making in relation to the regulation of the Austria-Germany-Luxemburg bidding zone. Their experience in the context of a far larger and more complex bidding zone suggests that such informal cooperation can work successfully as part of the existing European framework.

If the need for cooperation between NRAs should increase over time, formalised arrangements for joint decision-making could be arranged on the basis of delegated authority from the NRAs. Such an approach would not necessitate the transfer of legal authority to a multilateral body.

An interesting example of institutionalised NRA cooperation, albeit one in which the joint body has been given legal decision-making responsibilities in some areas, is the Irish Single Electricity Market (SEM) Committee.[40] The SEM Committee oversees the joint Irish electricity market and has formal regulatory responsibility in relation to:

- management of the Trading and Settlement Code;
- the Market Monitoring Unit (which monitors compliance, notably in relation to market power abuses);

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[40] See the Electricity (Single Wholesale Market) (Northern Ireland) Order 2007, No. 913 (N.I. 7) and Section 8 of the Irish Electricity Regulation (Amendment) (Single Electricity Market) Act 2007). These arrangements are also stipulated by a Memorandum of Understanding between the Governments of Great Britain, Northern Ireland and the Republic of Ireland (See https://www.dccae.gov.ie/documents/SEM%20Memorandum%20of%20Understanding.pdf).

- the Market Modelling Group; and
- Single Market Operator regulation.

All regulatory matters that do not fall under the aforementioned scope remain in the hands of each of the respective NRAs respectively.

The NRAs are also well represented in the make-up of the Committee itself, which consists of three members from the Republic's NRA, two members from Northern Ireland's NRA, and two independent members.

Jointly, the NRAs work together through the Committee to harmonise transmission policy and define the systems and processes that constitute the high-level design of the integrated Single Electricity Market. The National NRAs continue to be ultimately responsible for regional cooperation, however specific functions have been transferred to the joint body with the agreement of the national governments. In the event of continued disagreement between the NRAs on issues related to cross-zonal capacity calculation or the definition of capacity calculation region borders, EU legislation allows the dispute to be escalated to ACER for resolution. However, the SEM Committee provides a more practical mechanism to undertake ongoing regulatory tasks that cover both NRAs, as well as to support cooperative regulatory development as needed.

The approach used in I-SEM could thus serve as a useful model for NRA cooperation as part of a multinational offshore bidding zone. Although the Committee is based on bilateral cooperation, the institutional arrangements that it embodies could be readily adapted to cover a multilateral bidding zone.

5.2 System operation

As with regulatory decision making, the extent to which novel arrangements are required in order to enable effective system operation as part of an international offshore bidding zone will depend on the complexity of the offshore system. Existing arrangements may well suffice in the near term and have the potential to evolve with the offshore system to ensure that arrangements continue to suit the changing needs of the system.

The need for coordination among system operators onshore means that there already exist multiple examples of successful TSO coordination.

Again, the successful joint operation of the Austria-Germany-Luxembourg bidding zone demonstrates that even a relatively informal system of TSO cooperation based on mutual consent among operators can work. Such a setup may well be appropriate where the system, and hence operation decisional making, is fairly simple.

More complicated coordination among existing system operators may be facilitated by the creation of Regional Coordination Centres (RCCs), as set out in the EU Regulation 2019/943 (Recitals 53 – 59, Articles 35-47). TSOs have some flexibility as to the functions delegated to the RCCs, but the RCCs are intended, in particular, to support coordinated capacity calculation and operational planning in the relevant region.[41] Similar to the structure of the SEM Committee, the management board of each RCC will be composed of members representing the region's transmission system operators.[42]

New tasks for RCCs can be proposed by Member States or the Commission and so their function can readily adapt to the evolving needs of the offshore system, allowing for a gradual expansion of joint activity between TSOs while still maintaining the operational authority of national TSOs. However, the geographic scope of the RCCs is based on capacity calculation regions and consequently, may fail to provide sensible coverage of future offshore bidding zones. Since the creation of new bidding zones will also create new bidding zone borders, a revision to the definition of RCC jurisdictions may therefore

[41] For other tasks, see Article 37.
[42] See Article 43.

be appropriate to account for emergence of significant bidding zone boundaries around sea basins.

Some system operator functions, such as those requiring real-time assessment and response, may more naturally fit within the capabilities of a single system operator, given the need for rapid action and the overlap with system operators' existing functions. How can that functionality be provided to offshore systems that naturally traverse national boundaries, for example as part of an offshore hub fed by offshore generators in multiple countries?

Again, in considering the appropriate institutional response, it makes sense to think about how the system is likely to evolve over time. Initially, real-time system operations offshore will be handled by existing onshore system operators, as is the case today. If the offshore system develops such that system operation boundaries naturally cross borders, it may well make sense for *one* SO to take operational responsibility for the relevant zone, with financial and legal responsibilities continuing to be divided among TSOs.

Such an arrangement could be put into practice through the use of service agreements among TSOs. Under these agreements, operational responsibility would be assigned to a lead TSO and the agreement would define how the costs of the lead's operations are shared and how any risks are allocated. Expectations and incentives in terms of performance quality could also be set in the agreement, potentially with direct reference to the relevant incentives under the respective national regulatory regime.

One key advantage of this model is that it implies close integration between system operation activity off- and onshore. This is likely to support efficient management of balancing activity, as discussed in Section 2.3.3, since the offshore system operator can be expected to have immediate access to onshore balancing services on at least one shore.

Current arrangements in Ireland's SEM provide a current example that resembles this approach. There, EirGrid is the licensed transmission system operator in the Republic of Ireland and SONI is its Northern Irish equivalent. Both TSOs, while maintaining their own separate resources, have formed a contractual joint venture, called SEMO (Single Energy Market Operator), which conducts shared system operation responsibilities. SONI also effectively outsources some of its functions to EirGrid with the sharing of functions and cost sharing arrangements set out in two agreements between the relevant organisations.

It is important to note that, since the creation of the Single Electricity Market, EirGrid has taken over SONI. As a result, the formal contractual relationship between the TSOs may be less explicit than that required for the outsourcing of real-time system operation as part of an offshore bidding zone. However, the Irish example does nevertheless provide a useful model for potential TSO cooperation offshore.

If the offshore system becomes sufficiently complicated to warrant it, real-time system operation responsibility could also be transferred to a dedicated system operator, potentially organised as a joint venture among the participant TSOs. Again, this change would be readily supported by the initial use of inter-TSO service agreements, since the roles of the ISO would then be well-established.

5.3 Bidding zone determination

Another potential challenge associated with the creation of offshore bidding zones is determining these zones' borders. The creation of new zones and significant changes in network topology over time may well trigger disagreements as to the appropriate delimitation of these zones and a process for determining the appropriate configuration of zones in the event of disputes will therefore be needed.

Again, this challenge is neither new nor unique to offshore zones, as bidding zone disputes in recent years have shown. As a result, the necessary regulatory arrangements are already provided for in EU Regulation 2019/943 on the internal market for electricity (hereafter the Electricity Market Regulation, EMR). The regulatory document outlines the most important measures to ensure overall market efficiency and adequate congestion management.

According to Art. 14(1) EMR, bidding zones "shall be based on long-term structural congestions in the transmission network" and bidding zones should not contain structural congestion. Congestion within a bidding zone may be allowed temporarily if this congestion has no impact on neighbouring price zones or at least 70% of cross-zonal transmission capacity is made available for trading (Art. 16(8) EMR). Corrective action to eliminate long-term structural congestion within bidding zones is always required.

To keep track of existing and newly forming structural congestion, ENTSO-E must carry out a bidding zone review every three years that serves as a basis for follow-up actions by ACER, NRAs, TSOs, the Member States concerned and, ultimately, the European Commission (Art. 14(2) EMR). Where long-term structural congestion is identified within a bidding zone and the bidding zone configuration will not be amended to reflect this congestion, a (multinational) action plan needs to be developed that sets out the measures that will be taken to resolve congestion (Art. 14(7); Art. 15 EMR).

Regional Coordination Centres will also review cross-zonal capacity on a quarterly basis and these reviews are intended, amongst other things, to verify whether the required minimum level of cross-zonal capacity is being made available to the market. As noted in the legislation, derogations from cross-zonal capacity allocation rules "should be carefully monitored and transparently reported to prevent abuse and ensure that the volume of interconnection capacity to be made available to market participants is not limited in order to solve congestion inside a bidding zone" (Recital 21, EMR).

While the Electricity Market Regulation defines the principles for bidding zones delimitation and the circumstances that can lead to a review of current bidding zone configurations, EU Regulation 2015/1222, the guideline on Capacity Allocation and Congestion Management (CACM), sets out the details of the bidding zone review process.

Article 32 of CACM defines which entities can trigger a bidding zone review. These include:

- ACER, following a technical bidding zone review by ENTSO-E;
- multiple NRAs responding to an ACER recommendation;
- the TSOs of a capacity calculation region and all adjacent TSOs concerned by any new configuration;
- a single NRA or TSO if the reconfiguration's impact does not significantly affect adjacent TSOs' control areas; and,
- Member States themselves.

Article 33 of CACM sets out in greater detail the criteria to be considered as part of a review. These cover issues related to network security, market efficiency and the stability and robustness of bidding zones. Finally, Article 34 defines the process of regular assessments of structural congestion every three years. These are intended to serve as the basis for a periodic reassessment of bidding zones in the EU market, but do not necessarily trigger a bidding zone review.

The hope is that TSOs, Member States and NRAs can agree on any modifications to zonal delimitations based on the assessment criteria and analysis undertaken by ENTSO-E. However, if no consensus can be found among these parties and the Member States in the respective zone are unable to resolve the congestion caused by the existing bidding zone design, e.g. through the action plans described above, the Commission already has the authority to make decisions on bidding zone delimitation as a matter of last resort.

The types of issues relevant to offshore bidding zone delimitation are therefore already addressed by existing regulation and the process established under these rules should be sufficient to resolve any future disputes related to newly formed offshore zones.

What does not exist in the current regulation, however, is a forward-looking mechanism to consider bidding zone modifications consistent with the strategic development of a sea basin. This is unsurprising, since bidding zone design needs to relate to the intended structure of the offshore system and long-term strategic planning of the offshore system has generally not been conducted as part of formal regulatory processes. There may be value in such a forward-looking market design process as a means of providing some forward visibility to investors of potential changes. However, it only likely to make sense as part of a more general strategic exercise, for example one related to the revised TEN-E or Ten Year Network Development Plan processes.

Until then, Member States, NRAs and TSOs will need to consider whether the creation of a new bidding zone is appropriate when assessing proposals for hybrid projects and pursue the creation of a new bidding zone where appropriate.

5.4 Conclusions

As we have set out in this section, offshore bidding zones need not be multinational in nature and, where they exist within a single country's exclusive economic zone, can likely be readily addressed through the country's existing arrangements. However, even where system developments imply the creation of multi-national bidding zones, such zones are not unprecedented, with existing examples of multi-national cooperation and coordination related both to regulation and system operation. This experience suggests that suitable governance arrangements for such zones can be established.

On regulatory decision-making, we consider that cooperation among the relevant NRAs is likely to reflect the most appropriate model since it avoids the need to transfer regulatory authority. Such cooperation could be supported through the creation of joint NRA committees with delegated authority over specific areas. Here the SEM Committee provides a useful model.

On system operation, mechanisms to support TSO cooperation and coordination already exist. Regional Coordination Centres could support coordination among onshore system operators and their functions are sufficiently adaptable to be tailored over time to the needs of the offshore system. The current geographic coverage of RCCs does not naturally support cooperation around sea basins, given the currently limited relevance of the associated cross-zonal borders. Consequently, if new bidding zones were to be created in these basins, new RCCs with a geographic scope better suited to the needs of the offshore network might have to be created. Where real-time decision making is required, we consider that it may make sense for an existing onshore system operator to take on this role. We imagine that this could be achieved through the use of inter-TSO service agreements. Where the complexity of the system requires it, existing system operators could also establish an ISO for this purpose, potentially as a joint venture.

On bidding zone delimitation, the regulatory framework established in the CACM regulation already establishes processes for the creation of new bidding zones and the resolution of disputes concerning bidding zone delimitation.

Given this, it should be possible to effectively govern any new bidding zones through natural extensions to the processes and regulation already in place.

What the current regulation does not provide, however, is a mechanism to motivate or signal changes to bidding zone arrangements in support of the future large-scale development of renewable offshore generation. As such, while existing regulatory arrangements are unlikely to act as a barrier to the effective governance of future offshore zones, they also do little to directly motivate a transition to such zones. As noted previously, a consideration of specific future-focussed bidding zone modifications probably only makes sense alongside a vision of long-term system development and, as result, such a process would probably need to form part of a wider strategic system planning exercise.

6 CONCLUSIONS AND RECOMMENDATIONS

MAIN MESSAGES

- Neither the use of offshore bidding zones nor of home markets is superior across all of the criteria considered.
- On balance, the use of offshore bidding zones is the better approach to maximise European welfare and enable the mass deployment of offshore generation.
- Unlike the Offshore Bidding Zones approach, pricing is distorted under the Home Markets approach. This can lead to welfare losses as a result of inefficient dispatch and investment behaviour.
- The Offshore Bidding Zones approach can readily adapt to changes in the offshore network. In contrast, the rigidity of the Home Markets approach can create perverse outcomes, like the need to flow power against price differentials.
- Such conspicuous problems are liable to undermine confidence in the regulatory framework and harm investor confidence in the longer term.
- The Home Markets solution also suffers from a need for both greater system operator activity, to 'fix' infeasible market dispatch solutions, and significant regulatory reforms.
- Despite its advantages, the Offshore Bidding Zones approach may hamper some investments in hybrid projects because there can be a redistribution of project revenues from generation owners to the congestion income allocated to TSOs. For the specific network configuration modelled, we observe an average overall reduction in generator revenues of 1-5%.
- In the near term, support payments for generators may need to compensate for this.
- Options to redistribute revenues among transmission and generation owners should be considered further as a possible means to support investment in generation.
- Workable arrangements exist to support regulatory governance and system operation in offshore bidding zones.
- However, current regulatory arrangements do not provide a clear route to motivate or signal the need for forward-looking bidding zone changes at a sea-basin level consistent with the mass deployment of generation offshore. Such a process would likely have to be a part of a wider strategic system planning exercise.

As part of this work, we have conducted a wide-ranging and systematic assessment of alternative market arrangements for hybrid offshore projects. In particular, we have considered the relative merits of alternative bidding zone arrangements, focussing on the choice between developing offshore bidding zones or else tying prices offshore to an onshore 'home' market. A summary of our assessment of these options against the assessment criteria considered is provided in Table 10 below.

As can be seen from this table, neither option is strictly superior across all criteria. While the Offshore Bidding Zones option has the advantage that it provides efficient price signals and more naturally supports efficient dispatch, it could – depending on the topology of the specific project – end up harming the generation investment case and frustrating otherwise commercially viable projects. In contrast, the Home Markets option is more likely to facilitate commercial investment in hybrid generation using existing support schemes but requires significant regulatory reforms to avoid significantly undermining dispatch efficiency.

On balance, we believe that the use of offshore bidding zones is necessary if the market arrangements are going to maximise European welfare and enable the mass deployment of offshore generation.

The Offshore Bidding Zones option results in prices that accurately reflect the marginal value of power generated or consumed offshore and, consequently, ensures that dispatch and investment decisions made based on these prices are efficient and welfare maximising. Welfare losses resulting from the use of the Home Markets arrangements can be expected to grow with the size of the offshore network, but even in the near term, losses can result from the inefficient scheduling of trade across zones.

Whereas the Offshore Bidding Zones approach ensures that prices can readily adjust to an evolving offshore system, the Home Markets approach risks looking increasingly broken in a world where changes to asset configurations result in the need to flow power against price differentials, offshore consumers are not responding to changing conditions offshore and subsequent investment decisions are being distorted by inefficient price signals.

Once these challenges become apparent, investors are likely to have concerns about the stability of the overall regulatory environment. It is, therefore, difficult to see how the adoption of the Home Markets approach can credibly support the very large quantities of offshore generation implied by European ambitious for emissions reductions out to 2050.

While the Home Markets option might appear like an attractive fix to encourage investment in generation, it sets up a series of hurdles for subsequent deployment. As we have shown, very significant changes in regulation would be needed to avoid the curtailment of offshore wind implied by the requirement to make cross-zonal capacity available to the market. In our analysis, we have assumed that this regulatory challenge is overcome by the creation of an unprecedented level of priority network access for offshore generators. However, this solution implies a degree of discrimination between market parties that may be fundamentally inconsistent with the Treaty on the Functioning of the European Union and, even if legal, gives rise to other problems, such as the potential need to flow power against price differences.

The Home Markets approach also implies a much greater role for system operators, given the mismatch between the technical capabilities of the power network and the way trading possibilities are reflected in the market design. This mismatch requires system operators to estimate offshore injections ahead of the market and to reserve transmission capacity within the network accordingly. It also implies that system operators may need to be active in the market, for example through countertrade, to try and encourage market solutions that more accurately reflect the constraints facing the system.

In short, a deeper consideration of how a Home Markets setup would operate when faced with a complex offshore network topology quickly exposes the need for a mess of out-of-market adjustments to keep the system working. Given this, it is unlikely to form a solid foundation for mass offshore deployment.

That said, we recognise that the use of offshore bidding zones entails its own challenges, the most significant of which is its tendency to lock up part of hybrid project's value in the form of congestion income. This will tend to disadvantage hybrid generation projects in competition for commercial investment capital when they are compared with direct-to-shore connections or onshore generation projects, which pay for transmission access at cost.

One possibility to address this challenge is the use of dedicated support schemes for hybrid-project generation. However, the level of support required by hybrid generators may still exceed that required by non-hybrid offshore projects, and thereby potentially decrease the total volumes of offshore generation that can be deployed.

We have therefore also looked into a variety of alternative approaches intended to ensure that the initial market distribution of hybrid project revenues does not hamper the construction of viable projects and that such projects can be realised on a fully commercial basis in the future. Given the short window available for this work, however, we cannot pretend to have resolved this challenge conclusively. Rather, we consider that the issue is worthy of further dedicated study.

What we can say is that there are enough emergent solutions that it is reasonable to expect that some means of resolving this problem can be found. If pressed, we would suggest that the most appropriate regulatory response is probably to allow the congestion income from hybrid projects to be redistributed among the project's participants. This would free up the industry and national governments to develop solutions while the details of projects are still being worked out and avoid potential regulatory lock-in to an approach that might, in hindsight, seem ill-conceived.

On the governance of potential offshore zones, we conclude that workable arrangements exist and, in many cases, involve only limited extensions to current practice. Offshore bidding zones that do not cross national borders could be governed using existing national arrangements. For multinational zones, regulatory governance could be provided for through NRA cooperation, possibly institutionalised in a joint committee. System operation could be conducted by an existing system operator and underpinned by TSO service and cost-sharing agreements among the responsible system operators. In both cases, these arrangements are precedented by the experience of the Irish Single Electricity Market. It must be noted, however, that the current arrangements do not actively promote forward-looking considerations of amendments to bidding zone design on a sea-basin level consistent with the rapid deployment of offshore generation. As such, the current arrangements cannot readily motivate or signal the need for such changes. Given the necessary link between bidding zone design and the system's future configuration, any such process would likely have to form a part of a wider strategic system planning exercise.

Table 10: Summary of the Best Option Relative to Each of the Assessment Criteria

Criteria	Best option	Comment
Dispatch		
Efficiency	OBZ	
Market manipulation	HM	Risks are manageable under both
Investment – Environment		
Predictability	OBZ	Does not rely on potentially unstable regulatory commitments
Investment – Generator		
Commitment to a hybrid configuration	HM	HM shields generators from risk of lower capture price or limited transmission access
Viability	HM	Higher generator revenues
Efficiency	–	OBZ gives efficient price signal but may hamper investment in some efficient projects
Support schemes	HM	Existing schemes can be used with only minor adjustment
Investment – Network		
Viability	OBZ	Higher congestion incomes, although incentive impact may be small or zero for a TSO
Efficiency	–	See Generator Investment Efficiency above
Investment – P2X		
Viability	OBZ	Lower power prices
Efficiency	OBZ	Price reflects marginal cost of consumption at hub
Balancing and Congestion Management		
Efficiency	OBZ	No need for intraday corrections and efficient imbalance settlement price
Support for flexibility	OBZ	Better incentives for offshore congestion management services
Curtailment	–	OBZ may be more likely to result in curtailment with negative prices
Regulatory Compliance		
Consistency	OBZ	HM option assumes priority access for offshore injections
Cross-Zonal Hedging		
Viability	–	Viable under both options
Political Acceptability		
Subsidiarity	–	No impact
National flexibility	–	Both accommodate diversity in national arrangements
Discrimination	OBZ	Priority access under HM may be discriminatory

System security		
Operational security	OBZ	Better reflects transmission constraints in market and imbalance price
CZC certainty	OBZ	CZC does not depend on offshore injections
Scalability and Adaptability		
Adaptability	OBZ	
Anticipatory investment	HM	Very little difference between the options as this is largely driven by the effectiveness of the planning system and by national regulators' approaches to eligible costs
Futureproofing	OBZ	Accurate price signals support consumption and investment efficiency

POSSIBLE CHALLENGES UNDER THE CURRENT GOVERNANCE AND REGULATORY FRAMEWORK

Although this study is primarily concerned with the market arrangements that ought to be applied to offshore hybrid projects, we have also briefly considered the wider suitability of the existing regulatory and governance framework in realising the future mass deployment and operation of offshore generation. Here we have drawn heavily on the comments made to us by NRAs, TSOs and offshore wind developers as part of this project. As such, these reflections are best regarded as a summary of those raised by stakeholders, rather than the results of a fully independent and comprehensive assessment of the challenges facing the development of offshore generation. They are intended to provide a useful reminder of the some of the other broader issues worthy of consideration.

Energy-only market design

Regulators noted that commercial investments in generation capacity may become harder, or at least more risky, due to structural changes in the power sector. These changes are liable to affect all generation and not just the offshore sector. Specifically, low-carbon generation technologies will tend to have high capital costs, low variable generation costs and limited flexibility. These features are liable to contribute to far greater short-term price volatility. At the same time, the wider decarbonisation of the economy will require the deployment of large quantities of additional generation capacity. These deployments will often have relatively long lead times and will need to be made to meet uncertain policy-driven increases in demand resulting from the electrification of other sectors. Premature capacity deployment, where generation capacity additions outpace policy-driven demand increases, may result in protracted periods of low prices. Conversely, delayed investment in generation capacity may ensure that high power prices act as a brake on the decarbonisation of other sectors

In this context, traditional commercial investment in generation capacity based on a simple strategy of wholesale market participation may be comparatively unattractive and pose a real challenge to channelling low-cost private capital towards the deployment of all forms of generation, including offshore.

One offshore developer suggested that the risk posed to developers by policy-driven demand developments ought to be addressed through the use of risk sharing arrangements like the two-way Contracts for Difference (CfD) scheme used in the United Kingdom, in which developers and consumers (via Government administered contracting) effectively agree the price of power in advance. In this way, the developer can discount the risks of policy-driven demand failing to materialise and consumers are secured against high power prices if demand increases outpace additions in generation capacity.

This developer also highlighted the importance of ensuring that market arrangements facilitate the use of long-term corporate Power Purchase Agreements (PPAs) as a means of ensuring the bankability of generation projects. Such agreements are largely equivalent to the two-way CfD arrangement described above, but could be entered into without the need for direct Government involvement. Rather, they would be used by large consumers or suppliers to source power directly from project developers at prices agreed at the development stage.

Long-term system planning

The offshore wind developer we spoke with also highlighted the importance of maritime spatial planning and long-term network planning to ensure the efficient use of space and enable anticipatory investment in network infrastructure. Here, their implicit concern was that existing planning processes were not sufficiently focussed on mapping necessary developments to meet long-term climate and energy policy targets. This led to incremental revisions and plans that failed to establish a basis for anticipatory investments in the (onshore) transmission network, ultimately stymying the development of offshore generation. The developer also believed that the needs of non-network stakeholders were under-represented in current long-term network planning processes, notably the creation of the TYNDP, and that this contributed, at least partly, to the failure of these plans to more proactively chart a course consistent with long-term energy and climate targets.

One of the networks we spoke with highlighted the challenge they face in balancing the potential efficiencies associated with anticipatory investments against the risk of building stranded assets.

There is therefore a broader issue, likely embedded in national policy, regarding the regulation and political direction of TSOs, which influences extent to which regulated TSOs are incentivised to plan for and make investments consistent with meeting long-term political objectives as opposed to more concrete, near-term network requirements.

Benefits sharing

Multiple stakeholders highlighted the challenges involved in developing multinational projects with asymmetric benefits. This is obviously a very fundamental challenge related to how project benefits can be reallocated among Members States and their consumers in a way that supports unanimous agreement.

The more specific comments made in relation to this issue included:

- a perceived reticence for NRAs to factor multinational social welfare impacts into their decisions;
- from a network, a concern that the Cross-Border Cost Allocation process might sour negotiation on cost distribution to the extent it was used by one party to unilaterally demand contributions from other parties; and,
- from a developer, a concern that the PCI process, though welcome, may not scale well given the administrative overhead involved and, as a result, struggle to cover the large number of projects where complex benefit distributions are likely to be an issue.

System security requirements

One specific concern that was raised on system security regulations and the use of offshore bidding zones related to the need to avoid excessive reserve requirements in such zones. Specifically, whereas it might be reasonable, in the context of a traditional onshore AC bidding zone, to require the relevant system operator to procure reserves in the zone sufficient to ensure that any export requirements from the zone could still be fulfilled even in the event of a failure on an import line, such a requirement was unlikely to be appropriate for an offshore bidding zone. In particular, such zones were likely to have very high cross-zonal transmission capacities relative to the volume of generation capacity within the zone and to effectively flow power across the relevant zone. Building dispatchable backup capacity in the offshore zone was likely to be more costly than locating reserve capacity in onshore import zones. As such, imposing reserve requirements offshore similar to those onshore, as a means to ensure the effective independence of flows across different cross-zonal connections, would lead to the adoption of unnecessarily costly reserve requirements.

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