Recommendations for an integrated framework for the financing of joint (hybrid) offshore wind projects

Written by
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External report by Guidehouse and Sweco

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Final report

Prepared for the European Commission

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Executive Summary

Offshore targets in North Seas Energy Cooperation (NSEC) countries are ambitious but need to be revised upwards in light of the increased EU greenhouse gas (GHG) emission reduction target of 55% until 2030. The current 22 GW in NSEC and UK (12 GW in EU-27) will have to be increased to at least 180 GW (but more likely towards 350 GW) until 2050, depending on the chosen decarbonisation pathway. A major upscale in offshore capacities is required compared to the status quo.

In NSEC countries and the UK, there are a variety of designs for financing and cost recovery regimes for generation assets and connections to shore and interconnectors. None appear to outperform one another, but the national regimes follow partially different rationales. The Netherlands predefines zero-support costs in the context of favourable framework conditions and so exposes developers fully to market price risks. It selects projects not in a price-based auction but based on a multicriteria assessment (e.g. by assessment the developer's approach to mitigating revenue risks via power purchase agreements [PPAs]). Denmark is introducing a modified Contract for Difference (CfD) approach, seeking to expose developers and operators to short-term and seasonal price risks, but protecting them from long-term price risks. The UK does not expose developers and operators to market price signals (implementing an hourly calculated CfD) but focusses on private sector-led development of infrastructure elements in its offshore transmission owner (OFTO) model. Germany leaves defining the need for support to the competitive bidding process in which developers can submit positive or zero bids (and in the future possibly even negative bids for concessional payments), depending on how the developers assess the market situation going forward.

These schemes may co-exist and provide for offshore deployment within their national contexts. However, Member States have to cooperate on offshore deployment considering the required massive scale up and the unevenly distributed offshore potential in NSEC countries combined with unevenly distributed demand for electricity. Member States then have to decide which of the existing schemes to use for specific projects, whether to coordinate or align their offshore schemes or whether to implement new offshore regimes specifically tailored to the cooperation case.

In terms of the market arrangement, radially connected offshore wind projects (OWPs) may be placed in the existing bidding zones setups (i.e. the home zone [HZ] setup). For hybrid OWPs, the adequate market arrangement is yet to be defined. The HZ solution contradicts the rule of providing 70% of interconnector capacity to the market and would thus require a case-by-case exemption or a permanent redefinition of the rules for hybrid assets (infrastructure serving as interconnection as well as connection to shore). In certain cases, dispatch and interconnector use may be less efficient than under the offshore bidding zone (OBZ) setup. While potentially performing better from a social welfare perspective, an OBZ would result in lower revenues for OWP and higher revenue risks (related to negative prices with no support and compensation for OWP). Revenues would have to be either redistributed from transmission system operators (TSOs) to OWPs (which would require amendments to the electricity market regulation [EMR] and may be questionable from a conceptual perspective) or support schemes need to make up for the likely revenue loss. Regardless of the applied support scheme, the revenue risk related to negative prices remains; its significance largely correlates with OBZ's ability to improve dispatch efficiency across bidding zones. When determining the market arrangement, the full integration of OWPs and the gradual phaseout of RES support need to be considered.

Differentiating the cooperation hardware (i.e. interconnector functionality) from the cooperation software is essential to identify the various possible options to cooperate. The software includes the chosen cooperation mechanism according to the Renewable Energy Directive II (RED II), the choice of a support scheme (i.e. whether an existing one is used or a new one is set up), financing of support and a high-level decision on the transfer of RES statistics. The market arrangement is considered a boundary condition for the purpose of this report. For offshore cooperation, joint projects and the use of an existing support scheme appear to be adequate starting points before exploring more complex solutions like joint support schemes.

There are many options to setup joint (hybrid) offshore projects. Guidehouse identified five likely project setups covering the hardware and the software, including and excluding interconnector functionality to reduce the complexity of options, and making tangible recommendations. While variations of the proposed setups are likely, they serve as a blueprint to guide through the main design options of cooperation.

Support scheme design should not be limited to the form of support or the tender design, but it needs to include the process for site selection and the grid connection regime as these (next to the market arrangement) heavily impact the need for support in the first place (i.e. whether zero subsidy bids are feasible). In principle, the processes for site selection and pre-development may be organised in a centralised or decentralised manner. However, a centralised approach appears most suitable in the context of joint hybrid OWP. The grid connection regime needs to be differentiated into its key components, i.e. planning and design, commercial and finance, construction and interface risk as well as operations and reliability. For radially connected OWPs, a developer-built (i.e. decentralised) approach may be suitable to make use of the developers' incentives for cost-efficiency. For joint (hybrid) OWPs, and especially in hub solutions, a centralised approach appears beneficial. Foremost, the need to identify the adequate interconnector setup, which cannot connect to an arbitrary number of OWPs, appears to require a centralised approach.

Which form of support is recommendable depends on several impact factors. For projects with relatively favourable conditions and limited risks either no support, a fixed premium or upfront investment aid may be a suitable solution, albeit at potentially higher support costs compared to a de-risking scheme, e.g. a CfD. Addressing long-term revenue risks via a support scheme appears reasonable so long as this risk cannot be productively mitigated by the OWP through the choice of bidding zone. The long-term market revenue risk may be addressed through an asymmetric/one-sided sliding premium or a symmetric/double-sided CfD and is particularly important for projects with higher revenue and project development risks (such as OWP further offshore or within an OBZ).

When cooperating on OWP, Member States will have to agree on whether to provide support for an OWP and in which form. Given the different support scheme legacies and current schemes (e.g. hourly symmetric CfD in UK, yearly symmetric CfD in Denmark, multi-criteria assessment in the Netherlands and asymmetric sliding premium in Germany), cooperation will require substantial flexibility by the involved Member States to agree on a common support scheme design for cooperation projects (or to choose one of the existing forms of support).

The tender design does not appear to be overly challenging for joint (hybrid) OWPs. The key tender design principles valid elsewhere need to be adhered to, i.e. adapting the design to the specific (hybrid) context while keeping the design as simple as possible. Especially for large-scale and complex projects, giving enough consultation and bid preparation time appears key.

Storage and Power-to-X (PtX) technologies such as hydrogen will play an important role in decarbonising the future energy system, and their combination with the use of offshore wind power is increasingly discussed. These technologies have the potential to support the integration of large volumes of offshore wind power. Potential benefits of using parts of the North Sea offshore wind power for PtX solutions, such as (offshore) hydrogen production, are reduced need of offshore and onshore transmission capacity and reduced congestion in the transmission system. By increasing the demand for offshore wind power and potentially shifting parts of the offshore wind power to periods with higher prices on wholesale markets, PtX and storage technologies may improve the business case for offshore wind. At the same time, storage and PtX technologies are associated with significant costs (both CAPEX and OPEX), making additional financing necessary to enable their market launch and scale up.

For a coordinated approach to cost-benefit analyses (CBAs), existing methodologies and processes should be made use of as much as possible. The CBA takes on a social welfare perspective and helps to determine whether a project is worth pursuing or not. For some cooperation setups (i.e. radially connected OWPs without infrastructure component) a comprehensive CBA may not be necessary as these are not implemented for regular national OWPs. If projects are more complex, their impacts are deemed significant and—especially if EU funding in the context of Connecting Europe Facility (CEF) is envisaged—a CBA is necessary. We developed a detailed approach on how to make use of existing CBA methodologies for joint hybrid OWPs, combining the assessment of the infrastructure component with the assessment of the generation asset.

In contrast to the CBA, the cross-border cost allocation (CBCA) considers distributional effects of projects, providing ground to redistribute costs and benefits so key stakeholders are better off with a project than without it. This report provides a detailed set of cost and benefit indicators, based on the CBA approach developed for hybrid OWP. For the CBCA, we recommend keeping the streams for costs, revenues, and compensation separate between the involved parties and their respective responsibilities, i.e. impacts and compensation for TSOs (infrastructure and system effects) and for Member States (e.g. with a view to support scheme payments, RES target statistics, effects on wholesale market price, and the use of RES potential). The separation of impacts according to each stakeholder ensures a proper use of revenue and support levies and grid tariffs according to their legal basis. In this approach, the impacted parties compensate or get compensated for the effects related to them.

The report includes four case studies and conceptualises how the distributional impacts of a project may be adequately approached in a CBCA. Expanding the case studies and adding quantitative assessments may help to effectively show Member States and TSOs a way forward to advancing joint (hybrid) OWP. The aspect of a proper CBCA approach appears to be one of the main hurdles in a coordinated and cooperative approach to (hybrid) OWP deployment as only a few involved stakeholders are convinced they will be better off with cooperation than without it.

EU funding may play a key role in convincing stakeholders (Member States, TSOs, and project developers) that joint (hybrid) OWPs are worth it. CEF grants will be important in this context, but a proper coordination of CEF energy with the new cross-border RES funding line or even the inclusion of a new category in CEF energy for hybrid OWPs seems advisable. Additional funds from the planned Recovery and Resilience Facility may also become available to be used by Member States to (partly) finance joint (hybrid) OWP.

In terms of the integrated sequencing for the planning, tendering, and construction of hybrid assets, the lead times of various conceivable project setups vary considerably from 5–10 years related to the complexity of the configuration. A country-to-country connection is complicated to establish with existing regulations. Voltage level, frequency synchronisation, and power quality are among the technical issues where alignment of Member States can support more smooth and efficient planning and development. The use of common EU or international standards instead of national standards on the high voltage grid level, on the design parameters for offshore installations can support in reducing the timespan for developing these solutions and ensure more standardised solutions with the long-term aim of cost-efficiency in manufacturing, construction, and operation and maintenance. Through the development of interconnectors, several findings were realised. While TSOs and Member States have pragmatically solved barriers, coordination is key. Most gain can be made on the permitting and planning side. However, risk related to uncertainty regarding legislating cross-border cables, revenue regimes, and planning OWPs and interconnector capacity must be addressed.

Technical Summary

The development of large-scale offshore wind projects (OWPs) is an important precondition for achieving the long-term goal of decarbonising the energy systems in the EU. Such large-scale development of offshore wind requires significant investments in generation assets and the grid, and coordination among EU Member States and the UK and the joint development of cross-border offshore projects. Coordinated regional offshore development has the potential to reduce costs (especially when OWPs move further away from the shore and induce higher costs for grid connection) and limit environmental impacts compared to purely national approaches. In this context, hybrid OWPs provide potential for more cost-effective offshore development and yield further benefits for the connected energy systems. Hybrid OWPs are projects in which the development and implementation of offshore wind and interconnection capacity is combined. A hybrid OWP goes beyond a hybrid asset, which is understood here as infrastructure with the dual functionality of internal transmission and interconnection. This report's scope focusses on OWPs, which are built as a cooperation project and which may (but do not necessarily have to) include an interconnector functionality.

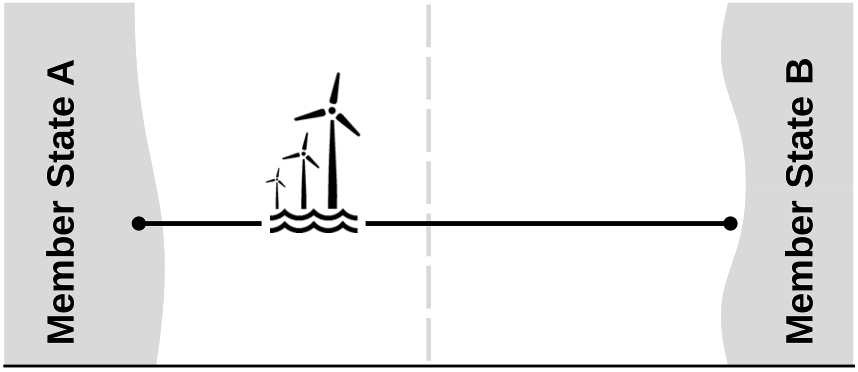

Figure 1. Basic setup of hybrid OWP *Source: Guidehouse*

Despite the benefits of and initial political support for hybrid OWPs, their development has been limited (with the exemption of Kriegers Flak). This is largely due to the complexities of planning, tendering, and financing hybrid projects, which require substantial coordination between the different assets (generation, connection to shore, interconnector) and the actors involved (project developers, TSOs, Member States). Moreover, an integrated approach for cost-benefit assessment (CBA) and cross-border cost allocation (CBCA) for such complex projects is required. Against this background, the objective of this report is to provide an overview of the current state of play of the financing and cost recovery of the various hybrid OWP components (i.e., OWPs, connections to shore and interconnectors) in the North Seas Energy Cooperation (NSEC) countries and, based on this overview, develop recommendations for an integrated framework for the financing of joint (hybrid) OWPs.

Task 1 - Overview of the current financing and cost recovery of generation support, connections to shore, and interconnectors in NSEC countries

Task 1 summarises financing and cost recovery of generation support, connections to shore, and interconnectors in NSEC countries. The analysis' focus includes NSEC countries and the UK, for which the current status and ongoing developments are presented. The analysis allows to formulate recommendations for financing and cost recovery of hybrid projects in Task 2.

Within NSEC countries and the UK, multiple countries have established offshore wind markets and have set development targets for 2030. Figure 2 shows the delta in capacity still required to meet the 2030 targets.[1]

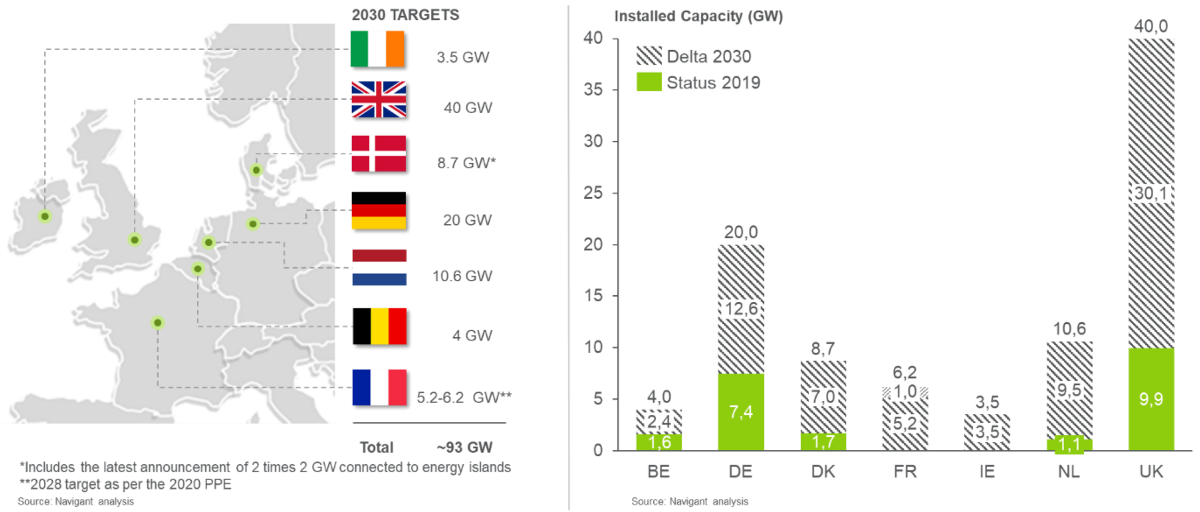

Figure 2. Offshore wind targets in NSEC countries and UK and installed offshore wind capacity vs. delta as per end 2019. *Source: Guidehouse analysis*

At the end of 2019, the installed capacity of offshore wind totalled approximately 22 GW.[2] The respective cumulative capacity of 2030 targets totals approximately 53 GW in 2030 in the NSEC countries (and 93 GW in NSEC and the UK) and can be considered as a significant step towards an accelerated scale up of offshore wind capacity towards 2050. Reaching the 2030 offshore targets requires adding approximately 41 GW in NSEC countries and another 30 GW in the UK. With an increased EU ambition level of greenhouse gas (GHG) emission reductions from 40% to 55%, the 2030 offshore targets are likely to be increased once more.

In 2018, the European Commission presented its “Clean Planet for all” vision, which included 230 GW to 450 GW of offshore wind capacity for the EU27 and the UK by 2050.[3] The highest level of this range was used by WindEurope to develop a 2050 vision with a higher granularity on country level.[4] It allocated 77% of all offshore wind capacity to the NSEC countries and the UK, resulting in a total capacity of 346 GW (of which approximately 80 GW allocated to the UK). Using the lower range of the Clean Planet for all vision and the same share for the NSEC countries and the UK results in a total capacity of 136 GW for the NSEC countries (and another 41 GW allocated to the UK). Regardless of the scenario, a massive scale up of offshore wind is required between 2030 and 2050.

Belgium, Denmark, Germany, and the Netherlands represent the NSEC countries with an established offshore market.[5] In addition, the UK is an important offshore player in the North Sea area; it has the highest capacity installed and by far the most ambitious planning for 2030. These countries have

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[1] Note that Norway and Sweden currently have no 2030 targets for offshore wind in place.

[2] WindEurope, 2020. Offshore Wind in Europe, Key trends and statistics 2019. https://windeurope.org/wp-content/uploads/files/about-wind/statistics/WindEurope-Annual-Offshore-Statistics-2019.pdf

[3] The wide range of offshore capacities results from the set of chosen scenarios, which put either emphasis on electrification, H2, P2X, energy efficiency, circular economy, cost efficiency, BECCS/CCS and/or sustainable lifestyles. See European Commission, 2018. In-depth analysis in support on the COM(2018) 773: A Clean Planet for all - A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy. https://ec.europa.eu/knowledge4policy/publication/depth-analysis-support-com2018-773-clean-planet-all-european-strategic-long-term-vision_en

[4] WindEurope, 2019. Our energy, our future. How offshore wind will help Europe go carbon-neutral. https://windeurope.org/wp-content/uploads/files/about-wind/reports/WindEurope-Our-Energy-Our-Future.pdf

[5] Also France intends to develop its offshore market towards 6.2 GW until 2030.

adopted different support schemes for the deployment of offshore wind, processes for site selection, different regimes for the connection to shore, and regimes to develop interconnectors:

- For the allocation of support, Belgium recently switched to an auction-based support scheme (with tenders expected from 2023) from the earlier negotiated-based approach (until 2020). In the new scheme, concessions for offshore wind sites pre-developed by the government rather than private developers will be auctioned (i.e. a centralised approach). The allocated form of support under the new scheme is to be determined through a Royal Decree. Belgium has a TSO-built grid delivery model. The responsibility for the development of offshore grid connection assets lies with the TSO Elia and is recovered through the grid levy included in consumers' electricity tariffs. Moreover, the Belgian TSO Elia is also responsible for building and operating interconnectors.

- In Germany, the Offshore Wind Energy Act (WindSeeG) sets the framework for offshore wind auctions, both for the transitional scheme in place between 2017 and 2018 and the auction rounds starting from 2021 onwards (the central scheme). Under the central scheme, the Federal Maritime and Hydrographic Agency (BSH) pre-develops the sites, which were determined in the Site Development Plan (Flächenentwicklungsplan).[6] Successful bidders receive monthly, (one-sided) sliding feed-in premiums. In 2017, Germany was the first country to receive zero-bid offers for two OWPs. To distinguish between multiple zero bids in future auction rounds, the draft of the Offshore Wind Energy Act of June 2020 foresees a concessional payment from the project developer to the TSO in case more than one bidder is willing to realise the site without a subsidy.[7] A new dynamic tendering process is proposed to determine this concessional payment. However, this proposal hasn't passed Parliament yet and is heavily contested by the offshore wind industry. Zero-bids have been made possible, among other factors, as a result of Germany's TSO-built grid delivery model, i.e. offshore wind transmission assets mostly fall under the responsibility of the TSO. Since 2019, the cost for connections for offshore wind are recovered through the offshore surcharge on the electricity bill of consumers. In Germany, the TSO is also responsible for building and operating interconnectors (i.e. TenneT in the North Sea).

- Denmark organised multiple offshore wind tenders with varying support scheme designs. Currently, there are two procedures for offshore wind development: an open-door procedure where developers propose sites and are responsible for site pre-development, and a tender procedure run by the Danish Energy Agency for specific sites (e.g. for OWP Kriegers Flak). Some of these tenders include negotiation phases with bidders in the allocation procedure (e.g. tenders for nearshore sites). Successful bidders receive fixed premiums (under open-door procedure), hourly (one-sided) feed-in premiums (for nearshore OWP), and (double-sided) hourly CfDs (for site-specific tenders). Denmark intends to organise a tender for the Thor offshore wind farm in 2021 allocating yearly calculated (double-sided) CfDs. Denmark has had several offshore grid delivery models in place, including an open-door policy (i.e. developer-built model) and a TSO-built model. For the upcoming Thor tender, a more developer-led model for offshore wind transmission assets will be adopted. Offshore grid investments are recovered through network tariffs. For the Thor OWP, costs are recovered through a Public Service Obligation (PSO) fee for end-consumers. The Danish TSO energinet.dk is responsible for building and operating interconnectors.

- The Netherlands have adopted several competitive tenders for the award of offshore wind sites and the allocation of yearly, (one-sided) sliding feed-in premiums. For the most recent offshore tenders, projects are selected based on a multi-criteria assessment without the allocation of any support (defined ex-ante). The Dutch Enterprise Agency (RVO) is

[6] Federal Ministry of Economics and Technology (Germany), 2017. Offshore Wind Energy Act (WindSeeG 2017). https://www.bmwi.de/Redaktion/DE/Downloads/E/windseeg-gesetz-en.pdf?__blob=publicationFile&v=9

[7] Federal Ministry of Economics and Technology (Germany), 2020. Draft Law amending the Offshore Wind Energy Law and other Regulations (Gesetzentwurf der Bundesregierung - Entwurf eines Gesetzes zur Änderung des Windenergie-auf-SeeGesetzes und anderer Vorschriften). https://www.bmwi.de/Redaktion/DE/Downloads/E/entwurf-eines-gesetzes-zur-aenderung-des-windenergie-auf-see-gesetzes.pdf?__blob=publicationFile&v=6

responsible for site selection and pre-development; grid development is the responsibility of the Dutch TSO TenneT. TenneT receives compensation for developing the offshore grid that the government pays out of the ODE levy on consumer tariffs (opslag duurzame energie). Moreover, the TenneT is also responsible to build and operate interconnectors.

- The UK organises multi-technology auctions for less established technologies, including offshore wind, that allocate hourly (double-sided) CfDs. Project developers are responsible for site selection in predefined zones. The UK has a developer-built grid delivery model in place. After their commercial operation date, developers sell offshore wind transmission assets to an offshore transmission owner (OFTO) through a competitive tender. The OFTO recovers its investments mainly through a Tender Revenue Stream (TRS) from the TSO. Under the UK's planning regime for interconnectors, private parties can approach the regulator (Ofgem) for an interconnector license. In addition to private operators, the UK also has TSO-led interconnectors set up by National Grid Electricity through subsidiaries.

There are a variety of designs for the current financing and cost recovery regimes for generation assets, connections to shore, and interconnectors in NSEC countries and the UK. None appear to be outperforming each other, so they are all adequate for offshore deployment. However, the national regimes follow partially different inherent rationales, putting more emphasis on market integration and developer-led infrastructure development or focusing more on revenue certainty and reduction of cost of capital.

Task 2 – Analysis of and recommendations on an integrated framework for the financing of hybrid assets

Task 2 provides analysis of and recommendations on an integrated framework for the financing of joint (hybrid) OWP. The recommendations are developed primarily with a view to NSEC countries and their cooperation. Nonetheless, these recommendations are largely applicable to other offshore regions, such as the Baltic or Mediterranean seas.

The integrated framework includes the following elements:

A. Approaches to cooperation and support scheme design, including (A1) the impacts of different market arrangements, (A2) the cooperation software, (A3) the basic structure of joint (hybrid) OWP, (A4) the support scheme design, and (A5) options to include Power to X (PtX) into the project setup.

B. Principles for a coordinated approach for a CBA and CBCA.

C. Recommendations on the use of the Connecting Europe Facility (CEF) and the Renewables Financing Mechanism for joint (hybrid) OWP.

D. Integrated sequencing for the planning, tendering and construction of hybrid assets.

A) Approaches to cooperation and support scheme design

A1) A key boundary condition for joint hybrid OWP: market arrangements

The market arrangement defines how hybrid offshore wind farms (including interconnector functionality) are allocated to specific bidding zones and in turn how interconnection capacity between these bidding zones is allocated. The home zone setup (HZ) means that hybrid OWPs bid into the existing bidding zones of their respective host Member State. In this setup, the offshore wind farms receive the electricity price of their home market and are able to operate as a Balance Responsible Party within that bidding zone. There are several challenges to this setup related to compliance with the Electricity Market Regulation (EMR)[8] and the Electricity Market Directive (EMD),[9] as well as efficiency considerations:

- Article 16, 8b of the recast of the EMR states that at least 70% of the physical capacity of each interconnector must be offered to market participants for the purpose of hosting cross-border trade. The connection from the OWP to the HZ would be considered an internal line (while providing interconnector functionality), in turn breaching the 70% rule. This would require either a case-by-case derogation approach (resulting in uncertainty for investors) or a permanent exemption for hybrid OWPs.[10]

- There is a concern that the HZ solution may result in less-than optimal grid and system operation as, in certain situations, welfare may be maximised by using the interconnector capacity for trade between the two bidding zones instead of using it for the infeed of the OWP.

The offshore bidding zone (OBZ) was proposed to address these challenges. In this market arrangement, wind farms bid into a newly created OBZ that reflects the structural congestion in the grid, i.e. the connections to shore. As a result, in an OBZ, all trade is considered to be cross-border and the 70% are seen as being available to the market (i.e. compliant with Article 16 of the EMR). The OBZ would provide transparency on the value of transmission capacities, as those would be reflected in the congestion rents. Moreover, the physical reality of the grid and OWP and interconnection flows are co-optimised by the flow-based market coupling algorithm, which may result in more efficient dispatch of units compared to the HZ.

Despite these advantages, there are various challenges related to an OBZ solution:

- **Governance:** A competent regulatory authority and a responsible system operator would have to be defined for cross-border OBZ.[11] In addition, entities have to be defined that are in charge for the regulatory approval and enforcement of market rules (e.g. regarding imbalance settlement and grid connections) for the OBZ. Establishing an OBZ may even require a broader bidding zone review, inducing significant transaction costs and impacts on many other market participants and existing generation assets.

- **Revenues:** The OBZ will usually result in the lowest price of all adjacent bidding zones because congestion will be on the side with higher prices. As a result, revenues for offshore operators decrease in the OBZ compared to the HZ solution.

- **Revenue risks may increase because of negative prices:** The OBZ will converge with negative prices in any of the adjacent bidding zones and so would experience more negative prices than each of the single bidding zones. Negative prices result in self-curtailment of the OWP and related income losses.

The OBZ results in more efficient dispatch than the HZ solution whenever it reflects negative prices in one adjacent bidding zone. The more the OBZ increases efficiency, the more the issue of negative prices effectively impacts the business case of OWP.

To be implemented, the HZ and the OBZ solutions require substantial legal changes on the EU and national level. From the perspective of financing hybrid OWPs, the key aspects are structurally lower

[8] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity.

[9] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity.

[10] Other legal concerns relate to Article 12 of the EMR (market based dispatch), Article 3 of the EMD (Member States shall not hamper cross-border trade) and Article 6 of the EMD (non-discriminatory grid access) which would also have to be assessed in more detail to check compliance with the HZ setup.

[11] OBZ may also be set up within national boundaries, but for many hybrid OWP setups, this does not seem likely / practical.

revenues and potentially higher revenue risks in OBZ compared to an HZ solution. Even if support schemes offset the structurally lower incomes, the increased revenue risk caused by negative prices persists.

A2) The cooperation software

A joint (hybrid) OWP is not only defined by its physical design. The cooperation software describes the cooperation setup apart from the chosen technical project configuration, including the following items:

- **Cooperation mechanism:** Member States may agree on implementing statistical transfers (Article 8 Renewable Energy Directive II [RED II]), Joint projects (Article 9), Joint projects with third countries (Article 11) or Joint support schemes (Article 13). Joint projects are likely to be implemented through the existing support schemes of cooperating Member States. The use of joint projects for single cooperation projects is likely. Joint projects between Member States and third countries may become relevant in the context of cooperation with the UK, as the UK plays a significant role in unlocking Europe's offshore potential. Joint support schemes are recommended in a multi-project cooperation approach but they entail significant transaction costs to be designed, agreed upon, and implemented.

- **Support scheme:** Either the support scheme of the host Member State or the contributing Member State may be used. Alternatively, a new joint support scheme may be set up (see details on the recommended support scheme design below).

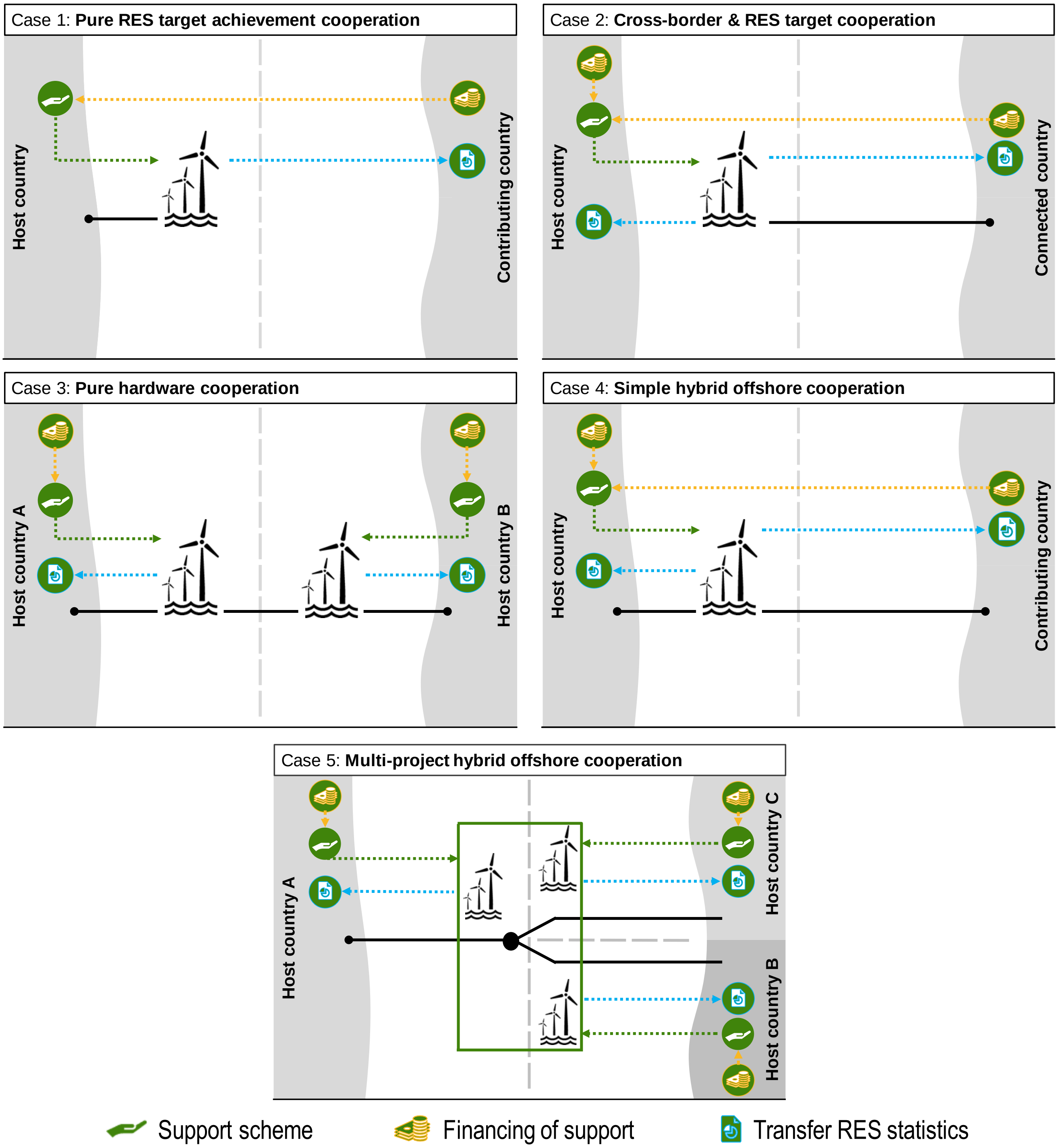
- **Financing of support:** For (joint) hybrid OWPs, support payments need to be refinanced either via the host country's levy scheme, the contributing country's levy scheme, or a newly implemented scheme. In addition, EU funds may be added to the support of hybrid OWPs while avoiding overcompensation of installations.

- **Transfer of RES statistics:** The electricity generated by joint (hybrid) OWPs initially counts towards the Member State's RES share in which the production asset is located. Whenever Member States cooperate on RES deployment and thus implement one of the cooperation mechanisms introduced above, part of the RES statistics is transferred to the contributing Member State. One approach is to distribute the share of transferred RES statistics based on the financial contribution to the support paid to the installation. This needs to be adapted whenever support is not required or when other costs and benefit elements are significant (see a detailed discussion of cross-border cost allocation below).

A3) Basic structure of joint (hybrid) OWP

There are a variety of options to setup joint (hybrid) offshore projects. We identify five likely project setups, including and excluding interconnector functionality, to reduce the complexity of options, and to make tangible recommendations.[12] These cases include the hardware setup and the cooperation software:

[12] Note that the cooperation cases build on the ones presented in Roland Berger 2018: Hybrid Projects. How to reduce costs and space for offshore developments. Available at: https://ec.europa.eu/energy/studies/hybrid-projects-how-reduce-costs-and-space-offshore-developments_
en?redir=1.



- **Case 1 RES target achievement:** In this setup, the OWP is located in the Member State it is connected to and no interconnector functionality is part of the cooperation project. The host Member State support scheme is used (with or without actual support costs). This case represents a joint project according to Article 9 of the RED II. The contributing country pays a defined amount per energy to the host country (for instance, part of the support costs) to receive a corresponding share of the RES statistics resulting from the OWP electricity production.

- **Case 2: Cross-border and RES target achievement:** In this setup, the OWP is located outside of the exclusive economic zone (EEZ) of the Member State it is connected to. The host country's support scheme is used (with or without support costs) and the host country transfers parts of RES statistics to the Member States the OWP is connected to, to compensate integration costs (for example).

- **Case 3: Hybrid - hardware-only:** In this setup, the project is a hybrid project, i.e. it includes an interconnector functionality. One OWP is located in each of two EEZs and connected to their respective shores while being connected to each other. Each Member States uses its respective support scheme and keeps the RES statistics produced from the OWPs in their EEZ.

- **Case 4: Hybrid - hardware and software:** This setup includes interconnector functionality as well. One OWP is located in Member State A (host country). The host country's support scheme is applied, but the two Member States finance the support to which the OWP is connected. In this case, RES statistics are transferred from the host Member State to the contributing Member State, according to the agreed share.

- **Case 5: Multi-project hybrid - hardware and software:** This setup would include an interconnector functionality and could include several OWPs connected to the interconnector via a hub, one in each Member State (i.e. A, B, and C). In this case, a new support scheme may be implemented (i.e. according to Article 13 of the RED II), which would be funded by all three Member States. The support could be auctioned centrally by a single dedicated authority or by a cooperation of the involved auction authorities (i.e. energy agencies or regulators). The RES statistics would be transferred according to a share of support scheme payments or any other CBCA agreement implemented by the involved parties.

A4) Support scheme design

In principle, an existing support scheme may be applied. The support scheme design here includes process for site selection and pre-development, the grid connection regime, the form of support (and related financing issues), and the tender design. However, if a new joint support scheme is envisaged or existing schemes are to be adapted for joint (hybrid) OWPs, the following recommendations may provide guidance:

The process for site selection and pre-investigation: Two general models for offshore wind site selection and pre-investigation exist, centralised and decentralised. In a centralised model, a state body undertakes zone and site selection and site pre-investigation and pre-development (including surveys and wind measurements) and bears the cost for this. This information is shared with developers bidding for the site in an auction. The advantages of this approach are that a holistic planning approach may be realised (via coordination of site and offshore capacity development) and that developers do not carry the risk related to site selection.

In a decentralised model, a state body undertakes zone selection, but project developers select sites, perform all required site pre-investigation and pre-development, and bear the cost for this. The decentralised approach's advantage is that developers can size sites optimally, making use of developer experience with selecting cost-effective sites. The downside includes a high risk for developers (e.g. sunk cost of site pre-development for developers unsuccessful in auction) and potentially macroeconomic inefficiencies.

For hybrid OWPs, cooperation between Member States could be beneficial to ensure appropriate site selection and timing of tendered sites and to prevent stranded assets. A centralised model can deliver this cooperation, which would be harder to attain under a decentralised model. Under a decentralised model, it would namely be more difficult to plan and coordinate developments due to uncertainty with project realisation timelines, involved stakeholders, and exact locations. Most countries already employ a centralised model for site selection and pre-investigation.

The grid connection regime: The grid delivery model determines who finances the grid connection and where the interface lies between a developer and the governing transmission system operator (TSO), transmission asset owner (TAO), or offshore transmission owner (OFTO). The grid connection regime covers planning and design, commercial and finance, construction and interface risk, and operations and reliability.

- Planning and design: Hybrid projects could benefit from a more coordinated planning of sites and offshore transmission asset development through a TSO-built grid connection regime due to the scale of offshore wind developments. However, the adopted regime should also consider leveraging the extensive experience of commercial developers with transmission asset developments to ensure timely realisation of the significant scale up of offshore wind power in the next decades. The complexity of hybrid projects could namely increase the risk for delayed grid delivery to developers.

- Commercial and finance: A TSO-built model could reduce cumulative societal cost through optimised use of assets through hubs and increased reliability and renewables integration in the onshore system. However, measures should be included to mitigate the risk of overspending by the TSO to optimise cost to consumers as TSOs are not subject to competitive cost pressures (as would be the case under a developer-built regime).

- Construction and interface risk: The construction and interface risks of offshore wind transmission assets included in hybrid project are related to TSO-built or developer-built grid connection regimes. A TSO-built model provides opportunity to coordinate and optimise offshore and onshore transmission asset development while a developer-built model provides a less complex interface that lies onshore. However, a key recommendation for hybrid projects where several countries would collaborate is that collaborating countries need to explicitly align on the responsibilities for construction and the exact interface between the developers and TSOs.

- Operations and reliability: Offshore wind transmission assets included in hybrid projects could benefit from higher redundancy in the design compared to single-line wind farms due to hubs and meshed connections. Developers and TSOs have different incentives to maintain reliability and especially in a TSO-built (or OFTO) regime an appropriate penalty scheme should be included for transmission asset unavailability.

While a developer-built (i.e. decentralised) approach may be suitable for radially connected OWPs to make use of the developers’ incentives for cost-efficiency, for joint (hybrid) OWPs and especially in hub solutions, a centralised approach is beneficial. Identifying the adequate interconnector setup (which cannot connect to an arbitrary number of OWPs) appears to require a centralised approach.

Form of support and related financing issues (e.g. PPAs): Support for offshore wind comes in various forms, including fixed premiums, sliding premiums, CfD, or upfront investment aid. In line with European regulations encouraging their use with few exceptions, most NSEC countries have implemented support schemes that require direct marketing of the produced electricity combined with (asymmetric/one-sided) sliding feed-in premiums or a (symmetric/double-sided) CfD. Upfront investment support (€ per kW) is another form of support; however, it is used less in the context of offshore wind support.[13]

[13] Note that investment support for offshore wind may become more relevant in the future, in case OWP apply for support under the new Connecting Europe Facility funding line for cross-border renewable projects or participate in the EU RES financing mechanism.

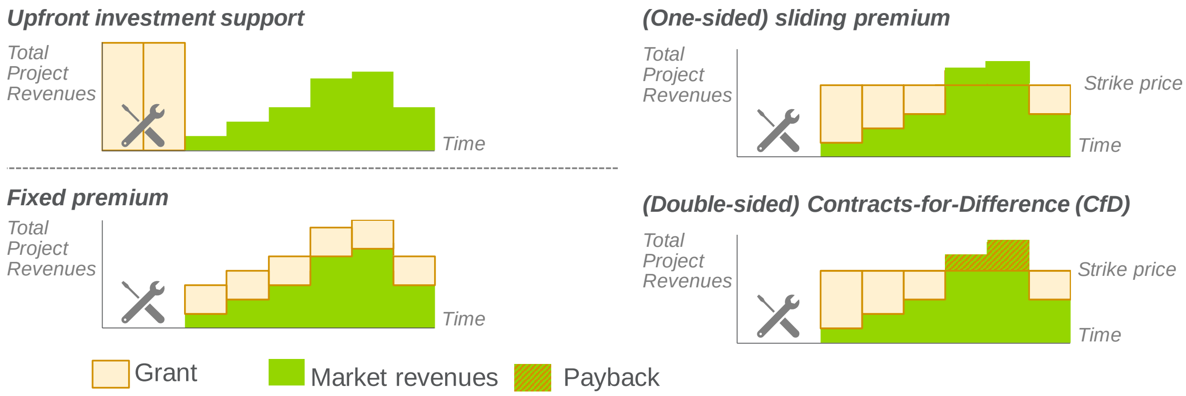


Figure 3. Overview of forms of support

Whether support payments are required for OWP depends on various factors such as coordination risks, site quality, proximity to shore, whether grid connections are included in the bid or not, permitting procedures, expectations on future wholesale market prices, and marketing routes that may transfer some of the revenue risks away from the producer (such as in PPAs).

Whenever these impact factors are favourable, merchant offshore projects may be feasible, as has been shown in the recent past. Merchant projects may be realised within various schemes, such as in an open door scheme where the developer initiates the entire project idea (including potentially site selection and grid connection), a sliding premium (or theoretically fixed premium or investment support) scheme with zero or even negative bids or a tender without any support (defined ex ante), and a multi-criteria selection of the projects. In addition, PPAs and other financial engineering approaches may distribute the risks from the support scheme (i.e. society) to the producer and offtaker (energy supplier or final consumer), but this shift of risks has balance sheet implications.

While there is some potential for risks being redistributed in merchant projects, we expect part of the offshore deployment to rely on societal risk insurance and the continued necessity of support schemes. With increasing offshore capacities of up to 450 GW in Europe until 2050, OWP are likely to move further away from the shores and to be partially implemented as hybrid projects. Hybrid offshore projects may be subject to additional project development risks (e.g. sites far offshore, increased coordination risks). On project level, this may increase the levelised cost of electricity (LCOE) of these OWPs and so—depending on wholesale market prices—impact the level of support or societal risk hedge required, limiting the potential for purely merchant projects. EU financial assistance and national/joint support schemes may become relevant, especially if (hybrid) OWPs are located within an OBZ. In this case, EU support on top of national/joint support may be warranted to partially compensate higher support costs resulting from the structurally lower revenues for such OWP.

Which form of support is recommendable depends on the impact factors mentioned above. For projects with relatively favourable conditions and limited risks no support, a fixed premium, or upfront investment aid may be a suitable solution (albeit at potentially higher support costs compared to a de-risking scheme, e.g. a CfD). Addressing long-term revenue risks via a support scheme is reasonable, at least if this risk cannot be productively mitigated by the OWP through the choice of bidding zone. The long-term market revenue risk may be addressed by means of an asymmetric/one-sided sliding premium or a symmetric/double-sided CfD and is important for projects with higher revenue and project development risks (such as OWP further offshore or within an OBZ).

(Double-sided) CfDs allow for high risk hedging but imply low market integration incentives since they shield project developers from volatile wholesale prices by offering a guaranteed price level. When implementing CfDs, attention needs to be paid to the exact design to avoid an inefficient dispatch of OWPs. Under an (asymmetric/one-sided) sliding premium, generators are free to decide to bid on a (positive) price below their generation costs (which then effectively functions as a floor price) and expect additional market revenues on top of the support payment or, in case of zero bids, rely on market revenues alone. The degree to which market revenue risks can be taken over by project developers are signalled by submitted bid prices and reflected in auction results. This flexibility to consider uncertain market revenues in their bid by increasingly lowering their bid price is the key advantage of a one-sided premium compared to a double-sided CfD. One-sided sliding premiums allow for a gradual evolution towards greater market integration, while under a double-sided CfD entailing a payback requirement, bidders are incentivised to bid a fully cost-reflective bid and market price risks remain with the society rather than project developers.

These theoretic recommendations do not necessarily reflect national policy preferences, national support scheme legacies, inherent support scheme logics (also across technologies), or existing path-dependencies. These aspects are relevant for Member States and we recommend maintaining this flexibility. In addition, when cooperating, Member States will have to agree on whether to provide support for an OWP and in what form. Given the different support scheme legacies and current schemes (e.g. hourly symmetric CfD in UK, yearly symmetric CfD in Denmark, multi-criteria assessment in the Netherlands, and asymmetric sliding premium in Germany), cooperation will require substantial flexibility by the involved Member States to agree on a common support scheme design for cooperation projects (or to apply one of the existing ones).

Tender design: While the cross-border nature of hybrid offshore projects is one of their defining characteristics, in most project setups, this primarily relates to the transnational infrastructure component (i.e. interconnector) of the hybrid project rather than the generation asset. Support for OWPs forming a part of a hybrid offshore project is likely to be tendered as part of single-item, site-specific auctions.

The design of tenders may relate to each country using its existing tender scheme for OWPs located in their respective territory (Cases 1 to 4) or to a joint support scheme (Case 5). In the case of hybrid projects (Case 3 and 4), this may imply different auction designs within one bidding zone. For Case 5, we assume that countries would set up a new joint support scheme, under which site-specific tenders for OWPs located in different countries and connected to an interconnector would be organised. This likely implies a common (or at least similar) tender design for each of the site-specific tenders organised under this joint support scheme.

- **Auctions vs. negotiated tenders:** Given the inherent legal and technical complexity of hybrid offshore projects, a negotiated approach may help avoid unintended participation barriers and risks for developers by granting project developers (and public authorities) the flexibility to adapt technical and commercial projects terms after the initial bidding stage. However, where price-based auctions are feasible (e.g. in case of a clearly-defined project setup and technical implementation requirements), they are advisable as they result in stronger competitive price building, faster project execution, and higher levels of transparency compared to a negotiated tender.

- **Tender procedure and pricing rule:** If the goals are efficient tender results and minimising transaction costs for all parties involved, static auctions rather than the more complex dynamic auctions can be used. For projects with higher technology and revenue risk (e.g. OWP further offshore, floating offshore), dynamic auctions may be used to promote the sharing of information among bidders in the bidding stage (e.g. on expected market values). Since bidders can correct their initial bid in the process, this decreases the risk of the winner's curse.

- **Pre-qualification requirements:** Pre-qualification requirements should be included in the tender design for hybrid projects to ensure only serious bids are considered and prevent compromised realisation timelines. When setting pre-qualification requirements, the right balance between setting an adequate incentive to realise the project and limiting excessive risks for project developers should be achieved. Compared to material pre-qualifications, financial guarantees are less prone to be adversely affected by different national framework conditions and reduce administrative burden for the auctioneer.

- **Realisation periods:** Realisation periods for joint (hybrid) OWPs need to reflect realistic project delivery periods, especially given their strategic and innovative nature, while avoiding lengthy realisation periods that encourage speculative behaviour and thus increase the risks that projects are not realised. For hybrid offshore projects, realistic project development cycles may vary under different project set ups compared to non-hybrid offshore projects or may be subject to uncertainties given the interdependency with large cross-border infrastructure assets (interconnection) that have multiannual development periods. Delivery periods should be aligned and coordinated with the required infrastructure development in terms of an adequate sequencing of the required transmission infrastructure and interconnectors to realise the overall hybrid project in time and avoid resulting project realisation delays of awarded OWPs.

- **Penalties:** (Post-award) financial guarantees and the associated penalties in case of non-delivery or delay beyond the contractually agreed realisation period are a suitable option to ensure the timely delivery of projects. Such financial guarantees are linked to penalties, as they can be confiscated if the bidder does not fulfil its contractual requirements. When determining the extent of penalties, a right balance needs to be struck between maximising realisation rates and avoiding excessive risks for project developers leading to low participation. For hybrid OWP, coordination risks may be higher compared to other renewable energy projects as result of the increased complexity and involvement of various actors (e.g. TSOs, Member States, private developers). In line with international best practice, imposing financial guarantees in the range of up to 10% of estimated project costs may be suitable to ensure project delivery.

A5) Impacts of including storage and PtX into the project setup

Storage and PtX technologies such as hydrogen (H_2) are set to play an important role in decarbonising the future energy system and have the potential to support the integration of large volumes of offshore wind power.[14] Potential benefits of using parts of the North Sea offshore wind power for PtX solutions, such as H_2 production, are a reduced need of offshore and onshore transmission capacity and reduced congestion in the transmission system. By increasing the demand for offshore wind power and potentially shifting parts of the offshore wind power to periods with higher prices on wholesale markets, PtX and storage technologies may improve the business case for offshore wind. At the same time, storage and PtX technologies are associated with significant costs (both CAPEX and OPEX) making additional financing necessary to enable their market launch and scale up.

Combining offshore wind power with storage or PtX technologies has the potential to change the entire project setup significantly by impacting the infrastructure costs, the need for connection and transmission capacities, the flow of electricity to the connected market areas, and the need for support payments. Taking H_2 as an example of a storage or PtX technology, two decisive aspects with regard to the technical configuration of combining H_2 production with offshore wind energy are the positioning of the electrolyser (onshore or offshore) and the connection of the electrolyser (ongrid vs. offgrid) and the electricity it consumes.

H_2 production - offshore vs. onshore: H_2 production in combination with offshore wind energy can be done onshore or offshore. When producing H_2, offshore several options exist for the placement of the electrolysers, including existing gas or oil platforms, dedicated new platforms or artificial islands, and in or on (e.g. on the gallery of) wind turbines.

Connection of electrolyser - ongrid vs. offgrid: Electrolysers can be connected to the electricity grid (ongrid connection, onshore or offshore) or supplied only by directly connected power plants, i.e. OWP (offgrid connection). A third alternative is that the electrolyser is supplied with electricity directly by the OWPs through a dedicated transmission cable and additionally via the grid (hybrid connection).

Including H_2 in hybrid projects increases the number of potential project configurations even further, as H_2 related infrastructure could be involved only in a subset or in all of the cooperating countries.

[14] For example, the joint declaration of the North Seas Countries and the European Commission from July 2020 emphasises the potential and importance of an offshore wind-hydrogen nexus for the future energy system. See: https://www.bmwi.de/Redaktion/EN/Downloads/M-O/nsec-joint-statement.pdf?__blob=publicationFile&v=2

How PtX solutions impact the financing of joint hybrid OWPs, depends on the support regimes for H_2 production, which have yet to be designed and implemented. Different instruments are being discussed to support H_2 production. The most prominent and fundamental models are:

- *Creating a market obligation based on a quota for (green) H_2:* The quota obliges natural gas traders to reach a share of green H_2 in their gas sales. Deviations in the physical delivery from the H_2 quota can be compensated by buying and selling H_2 certificates.

- *Upfront investment support for the electrolyser and H_2 infrastructure:* Grants provided as upfront investment support lower the equity and debt required, and the costs of debt. In principle, upfront investment support may be implemented without any additional (direct or indirect) operational support. However, depending on the costs of operation (mostly the costs of electricity), the provision of upfront investment support may not be sufficient to trigger investments in H_2 production.

- *Direct operating support for H_2 production:* Operating support can be designed to guarantee a certain minimum revenue per unit of H_2 produced (e.g. a fixed premium is paid on top of the market price).

- *Exempting electricity used from taxes and levies:* The electricity input for green H2 production could be exempted from taxes, levies, and surcharges. Such exemptions lower the costs of H2 production and are thus a form of indirect operating support.

The instruments listed above are not mutually exclusive and can be combined. For example, a Member State may implement upfront investment aid in addition to exempting electricity that is used to produce H_2 from taxes and levies to incentivise H_2 production.[15]

The design of the specific support system has a strong influence on when H_2 is produced and when it is not. It needs to reflect the general policy perspective on H_2 development, which can range from a goal of system optimisation and a goal to maximise H_2 production. If the aim is to support the energy system's optimisation, the direct use of electricity should generally be preferred overusing the electricity output of the OWPs to produce H_2, as the direct use of electricity is far more efficient. Ideally this signal should come from the market and not be distorted by production incentives, so investment aid seems the most appropriate form of support in this case, possibly combined with additional requirements to ensure system optimisation. On the other hand, incentivising H_2 production beyond what is optimal from a system perspective could be pursued to realise a market ramp-up of H_2 and provide a stable supply base to potential industrial customers. In that case, the goal could be to maximise the H_2 production from a particular asset. Production support for the electrolyser or a minimum production requirement are appropriate in this case.

The following paragraphs examine how electrolysers could affects prices and trade flows under different market arrangements. Locating an electrolyser to produce H_2 (or any other PtX facility) offshore, close to the OWP, raises questions on the effects such a set up would have on the operation of the electrolyser, the trade flows between the connected market zones and on the clearing price at an offshore hub. One possible assumption is that the electrolyser can source electricity directly from the OWP or from the grid and that is an independent actor on the market, it adjusts its operation according to market prices. In case of an HZ market arrangement, the power prices for the electrolyser and the OWP are equal to the prices onshore. Locating the electrolyser offshore has the same impact on power prices as in a situation where the electrolyser is located onshore. In practice, this price effect may be little or zero, assuming that the electrolyser demand is small compared to the supply and demand in the home bidding zone.

Price effects are more likely to occur in an OBZ than in an HZ arrangement. If the power price is low enough to operate the electrolyser, demand is created offshore, which shifts the demand curve at the

[15] It is also being discussed whether H_2 assets can be owned and operated by TSOs. In that case, they would be classified as a network element and costs associated with the instalment and operation would typically be recovered through grid fees, i.e. they would be passed on to electricity consumers and hence socialised.

hub and impacts trade flows. This may also affect the clearing price at the hub if the additional demand changes the occurrence of congestion in the transmission lines connecting the hub with the other market areas. In that case, the electrolyser and the OWP face a higher power price. The likelihood of such an effect, however, depends on the network typology (the relative scales of interconnector capacities, the electrolyser capacity, and offshore wind production at a time) and so needs to be evaluated specifically for each context.

The operation of an electrolyser offshore can positively affect the trade capacities between the onshore market areas. This is the case if the OWP and the electrolyser operate simultaneously. export and import capacities will be impacted by the balance of power production and power consumption at the hub. The general effect is similar in an HZ and OBZ arrangement.

B) Principles for a coordinated approach for a CBA and CBCA for joint (hybrid) OWP

Cost-benefit analysis (CBA)

To assess whether a hybrid offshore project should be built or not in the first place, the costs and benefits of the project need to be analysed through a CBA. When benefits outweigh costs over a defined period, the project has a positive net present value (NPV), adds value (to society), and is worth pursuing from a societal perspective.

Several CBA approaches for (cross-border) electricity infrastructure, storage, and generation projects currently exist or are being investigated. An offshore hybrid project combines generation, transmission, and potentially other components (storage, sector coupling). To capture the impact of hybrid OWPs on society, generation and interconnection components should be considered a single project. By assessing all components of a hybrid OWP in an integrated manner, the total societal costs and benefits can be captured completely, even if they are not fully quantified or monetised. However, this requires the alignment and coordination of stakeholder viewpoints and different CBA evaluation methods.

Existing approaches include:

- *CBAs for (cross-border) electricity infrastructure:* Electricity infrastructure is often part of the regulated asset base of national TSOs. For grid development projects, an established CBA methodology exists at a European level. ENTSO-E is responsible for the development of a CBA guideline for grid development projects under the Regulation (EU) No 347/2013.[16] Currently, the third ENTSO-E CBA Guideline is in the final stages of publication, adding new indicators and updating monetisation guidelines for indicators. [17] The ENTSO-E CBA Guideline assesses the costs and benefits of transmission TYNDP projects to European society as the basis for the European Projects of Common Interest (PCI) process. It provides a common basis for the assessment of projects brought forward by project promotors based on their societal value. Cost and benefit indicators are expressed around the themes of market integration, sustainability and security of supply focusing on a system-CBA rather than a project-CBA.

- RED II (focus on RES statistics and support costs): Cooperation on RES generation assets is legally embedded into the RED I and II.[18] The RED I and II focus on generation assets (and their support payments and RES target statistics) and do not define a general CBA approach

[16] ENTSO-E, 2019. Cost Benefit Analysis. https://tyndp.entsoe.eu/cba/

[17] ENTSO-E, 2020. 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects. https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/tyndp-documents/Cost%20Benefit%20Analysis/200128_3rd_CBA_Guideline_Draft.pdf (Draft *3rd ENTSO-E Guideline for CBA)*

[18] See for a detailed discussion Klessmann et al 2014: Cooperation between EU Member States under the RES Directive. https://ec.europa.eu/energy/sites/ener/files/documents/2014_design_features_of_support_schemes_task1.pdf and von Blücher et al. 2018: Design options for cross-border auctions, available at http://aures2project.eu/wp-content/uploads/2019/06/AURES_II_D6_1_final.pdf.

or a detailed CBA methodology. When assessing costs and benefits between Member States, the aim is on selecting the most important cost and benefit factors to support the political will to cooperate. Limiting the analysed cost and benefit elements reduces the complexity and the transaction costs of the cooperation.

- *CBA principles for cross-border RES projects under the CEF:*[19] In the context of the political agreement on the CEF regulation a system-level CBA for cross-border RES projects were identified.[20]

Building on the existing approaches and combining infrastructure and generation asset components, we suggest the following set of indicators to be used for a CBA for joint (hybrid) OWPs.

Cost and benefit indicators	Description
CAPEX	Capital expenditures of the project related to grid permitting and licensing, site (pre-) development, groundwork, design, equipment installation, temporary structures, equipment purchasing, financing costs, decommission for both infrastructure and generation components, and relevant grid connection and onshore grid investments
OPEX	Costs related to operation and maintenance of the project including generation and infrastructure components and relevant grid connections and onshore grid investments
Socioeconomic welfare	Consumer surplus, producer surplus and congestion rents
CO_2 emissions variation	CO_2 emissions through dispatch of power plants
Non-CO_2 emissions	Non-CO_2 emissions through dispatch of power plants
RES integration	RES capacity connected (MW) on a system or bidding zone level, or Reduction in RES curtailment (MWh per year) on a system level, or RES target contribution on a system level (share of RES in energy system)
Grid losses	Thermal losses due to transport of power not included in the demand profile used for SEW calculation
Adequacy	Power in the system to meet demand to consumers when required
Flexibility	Ability of the power system balance operation in the presence of high levels of variable renewable generation
Investment deferral	Avoided or deferred investment costs in grid infrastructure or generation, e.g. cost-efficient expansion of offshore (less €/kWh compared to national approach) Can be positive or negative (also national infrastructure cost savings)
Redispatch reserves	Reduction of necessary reserve for redispatch power plants
Other indirect effects	The project can result in a wide range of indirect effects that are more difficult to capture objectively or in quantitative/monetised terms such as, innovation, residual environmental, social or other impacts, air quality, job creation

[19] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

[20] Council of the European Union, 2019. Interinstitutional File: 2018/0228(COD). https://data.consilium.europa.eu/doc/document/ST-10418-2020-INIT/en/pdf

Cross-border cost allocation (CBCA)

The societal CBA deliberately excludes distributional effects. We assume that for most joint (hybrid) OWPs some stakeholders will lose while others win (which will be the case in any cooperation arrangement). Assessing the distributional effects of a project serves as a basis for re-allocating costs and benefits between stakeholders. This may ensure that the net benefits identified in the societal CBA are distributed to make the relevant involved stakeholders better off with the project than without it. The key stakeholders experiencing impacts from (joint) hybrid offshore projects are TSOs, the generation asset developer, and Member States (representing their consumers).

A range of boundary conditions and support scheme design options will have major impacts on the cost-benefit distribution and compensation requirements. First, the market arrangement will impact revenues for project developers and for TSOs. In the OBZ, revenues are effectively transferred from the project developer and operator to the TSO and support costs will increase. This shift in costs and benefits compared to the HZ solution has to be reflected in the CBCA.

The process for site selection and the grid connection regime also has major impacts on the initial distribution of costs and benefits and the need for compensation, as the related costs will either be borne by TSOs and appear in grid tariffs, or will be included in the bid in an auction and be financed by the support scheme and, as a result, by levy payers. This has implications on what party needs to be compensated (e.g. TSOs or levy scheme).

The CBCA is heavily impacted depending on whether H_2 is included in the project or not. These impacts concern costs for the electrolyser and the need to distribute them. Cost could be borne by the Member States but also could be refinanced via market revenues. The extent to which this is possible depends on the H_2 market (e.g. whether a H_2 obligation exists or not) and on the applied levy, fee, and tax regime for the H_2 production. The benefits would also be heavily impacted depending on how H_2 production and consumption count towards national RES shares.

To capture distributional effects between the cooperating Member States and stakeholders within Member States, the cost and benefit indicators from the societal CBA need to be adjusted. While the CBA approach prefers a monetisation for as many elements as possible, the CBCA decision for hybrid OWPs will be a negotiation outcome between Member States. They should have the flexibility to highlight certain cost-benefit impacts of a project that they deem significant or to exclude indicators that they agree to be less relevant to reduce the complexity of the analysis and the negotiation. In addition, some impacts may not be quantifiable but still be perceived as significant by the involved Member States, so they may include these aspects into the negotiation on the CBCA.

For the CBCA of joint (hybrid) OWP, we suggest following set of indicators:

Cost and benefit indicators	Impacted parties	Description of impact
CAPEX and OPEX of infrastructure element	TSO	One or more TSOs pre-finance the infrastructure asset, connection to shore and onshore reinforcement.
Congestion rents (part of SEW in CBA)	TSO	TSOs generate revenues from congestion, albeit to different extent for each TSO. Impact on each TSO also depends on market arrangement (OBZ vs. HZ).
Additional redispatch (redispatch reserves in CBA)	TSO	TSOs may increase or decrease redispatch as a result of project. Redispatch costs is refinanced via grid tariffs.
System flexibility (part of security of supply in CBA)	TSO	Flexibility increases in the case interconnector functionality is included in the project and it is impacted by the additional RES capacity added to the system as part of the project.
Investment deferral – infrastructure	TSO	Avoided or deferred investment costs in grid infrastructure or generation as a result of the project.

Cost and benefit indicators	Impacted parties	Description of impact
CAPEX and OPEX for generation asset	Generation project developer	Project developer pre-finances the generation asset.
Market revenues	Generation project developer/operator	Project generates income from selling at electricity exchange (or other marketing routes). Income depends on market arrangement (lower in OBZ compared to HZ).
Support scheme payments	Member States (their levy/taxpayers) and project developer	Member States make support scheme payments based on a pre-agreed share.
RES target statistics (part of RES integration in CBA)	Member State	Member State where production asset is located increases its national RES share according to electricity production
Effects on wholesale market price (part of SEW in CBA)	Member State (their consumers)	Cooperation project may decrease or increase wholesale market prices in each of the bidding zones, thus impacting cost of electricity for consumers and reversely support costs for existing RES plants in sliding premium systems
(Non-)CO_2 emissions	Member State	Project may increase or decrease emissions in each MS.
Use of RES potential (part of investment deferral in CBA)	Member State	The hosting Member State loses RES potential for purely national RES deployment.

After having identified the key impacts per stakeholder, the ones bearing costs but not receiving the corresponding benefits need to be compensated, those receiving significant benefits should contribute to the compensation.

Similar to the CBA, for the CBCA we build on existing approaches:

- When allocating costs and benefits for cooperation projects as defined in the RED (I and II) (i.e. generation assets) Member States agree to cooperate and identify the key cost and benefit elements of cooperation. Subsequently, Member States agree on a compensation model and on the specific allocation of costs and benefits. The allocation of costs and benefits in RES cooperation has been based on a selective and pragmatic approach to identify the key cost and benefit elements to be addressed.[21] The compensation is seen as the result of a negotiation process between the involved Member States.

- The approach to re-allocating costs is so far somewhat different for cross-border infrastructure assets (when part of the PCI process): the project promoter prepares the detailed technical description and project-specific CBA and submits the investment request to the impacted national regulatory authorities (NRAs), who in turn transmit the request to ACER and define a coordinating NRA. The NRAs (similar to Member States in the case above) identify the main costs to be allocated, agree on the allocation of the costs, and agree on specific payments. The NRAs adopt the coordinated decisions and notify ACER. In contrast to cost allocation for generation assets, the CBCA for infrastructure projects is based on a comprehensive CBA that aims for comparable analysis. The actual compensation happens in terms of cash transfers and is implemented by TSOs (and not Member States as in the cooperation mechanisms as defined in the RED I and II).

[21] Note that cost benefit allocations in the context of the cooperation mechanisms have only been assessed on theoretical levels for joint project and joint support schemes. See for a detailed discussion Klessmann et al., 2014. Cooperation between EU Member States under the RES Directive. https://ec.europa.eu/energy/sites/ener/files/documents/2014_design_features_of_support_schemes_task1.pdf, von Blücher et al., 2018. Design options for cross-border auctions. http://aures2project.eu/wp-content/uploads/2019/06/AURES_II_D6_1_final.pdf

The individual components of hybrid OWPs are legally related to the different impacted parties and their respective investment and revenue regime. Infrastructure is a core responsibility of TSOs, who refinance their investments via grid tariffs and congestion rents in a highly regulated market. Accordingly, the use of grid tariffs and congestions rents is defined in European and national legislation. By contrast, generation asset developers operate in a more liberal market context and generally refinance their investments via market revenues (and are free to choose their marketing route and business model) and support scheme payments. Member States aim for increasing RES shares and partially use support schemes for that purpose, financed either through levies or the general budget (i.e. taxes).

Mixing these investment and money streams may at first sight seem beneficial as it would allow defining a cooperation package covering the entire hybrid OWP. Bottom-line effects and a bottom-line compensation decision could be envisaged. However, mixing these elements for concrete compensation payment streams is likely to create multiple legal challenges and would potentially require substantial legal changes in the involved Member States and in EU legislation. For instance, national level grid tariffs usually cannot be used to make support payments to RES generation assets. Likewise, support scheme payments are usually not used to make grid investment (which depend on the grid connection model). Such a mixing of money streams in the context of a cooperation agreement would contradict the (justified) separation at a national level. Against this background, the streams for costs, revenues, and compensation should be kept separate between the involved parties and their respective responsibilities.

Although costs and benefits impacting TSOs should be kept separate from those relevant to Member States, the overall cooperation on joint hybrid OWPs needs to be pursued and driven forward by Member States. Even when respecting the separation of payment streams according to the different stakeholders, Member States will want to achieve an overall benefit from the cooperation (including the infrastructure and generation asset components).

The currencies available for allocating the costs and benefits across borders are cash payments and RES statistics. Between TSOs, this will happen for their respective impacts in the form of cash payments and between Member States in the form of cash payments, transfers of RES statistics, or a mix.

A relevant challenge in defining a CBCA is that the analysis of distributional effects and the resulting compensation decision happen before the project is realised and unfold its effects. This implies major uncertainties about the realised costs and benefits over a project's lifetime. A review clause solution implies uncertainties for the cooperating parties. A mix of conditional compensation and recognising the strategic value of cooperation (and so accepting some uncertainty) seems advisable. It could imply that the conditional compensation is realised between TSOs for the infrastructure and the resulting congestion rent. For the remainder of impacts, compensation is achievable between Member States, initially based on the share of support costs borne by each and a range of additional aspects which they deem relevant to determine the compensation. This compensation can then be based on the transfer of RES statistics and additional compensation payments. Which solution is advisable depends on the exact cooperation setup and the preference of the involved Member States, so no one-size-fits-all solution can be provided.

The report elaborates (without quantifications) how the suggested CBCA approach would work for the different project setups defined above. For each case study, we describe in qualitative terms which high-level impacts may occur for the involved stakeholders and subsequently how the costs and benefits may be redistributed to achieve buy-in from the stakeholders for the cooperation case. Where applicable, we discuss implications of the case on the cooperation software.

Recommendations on the use of the Connecting Europe Facility (CEF) and the Renewables Financing Mechanism for joint (hybrid) OWP

EU funding may incentivise Member States to cooperate on RES deployment and may reduce the costs to Member States when envisaging new and innovative project configurations (e.g. joint hybrid OWP in an OBZ). Especially hybrid configurations that entail interconnection and generation asset components may not be expected to rely on one single point of access to EU funding. Rather, these hybrid projects might have to combine funding from different sources, from the planned funding line for renewables cross border projects (c-b RES) and the more established CEF Energy/PCIs funding line targeting energy infrastructure.

Connecting Europe Facility (CEF), including new window for c-b RES projects

Since its introduction in January 2014, CEF is the key EU funding instrument to support the development of interconnected trans-European networks in the sectors of energy, transport, and telecommunications (i.e. CEF Energy/PCIs, CEF Transport, CEF Telecom). The Commission's proposal for the new CEF includes a category for cross-border projects in the field of renewable energy (c-b RES projects). On 8 March 2019, the European Parliament and the Council reached a common understanding on the proposal for a revised CEF Regulation for 2021-2027. According to it, 15% of CEF Energy/PCIs (€875 million, subject to final MFF decision) are made available for c-b RES projects. If that amount is reached, the Commission may increase it to 20% of the CEF Energy/PCI budget. The funding line shall also provide for possible blending with other EU programs including the proposed new InvestEU Fund.

The funding line shall provide support for:

- Grants for pre-feasibility studies for EU Member States and project promoters to assess and develop jointly beneficial Cooperation Mechanisms.
- Grants for technical studies, i.e. more detailed studies undertaken only once a cooperation or project was granted the status of a c-b RES project.

Grants for works for a limited number of c-b RES projects.

The proposed selection procedure (see Study ENER/C1/2018-554 for more details) includes various application stages that projects have to pass from pre-feasibility studies to receive grants for works (see Figure 4).

Figure 4. Overview of application stages for c-b RES projects (source: Guidehouse)

In principle, CEF grants may be used for both the infrastructure component (i.e. CEF Energy/PCIs funding line) and the generation component of hybrid OWP (CEF c-b RES funding line). For the generation component of hybrid OWP, the CEF c-b RES funding may be used as the single source of funding or CEF grants may be combined with support allocated through national/joint support schemes, including also from the Recovery and Resilience Facility (RRF). The single use of CEF financial assistance is more straightforward and avoids potential adverse effects (e.g. the risk of overfunding) that may arise if different funding sources at the national and EU levels are combined. If support from national/joint support schemes is combined with CEF financial assistance, this should follow a coordinated approach at the Member State level rather than an uncoordinated combination of CEF grants and support allocated through national/joint support schemes by individual project promoters. Additional funds from the planned Recovery and Resilience Facility may also be available for use by Member States to (partly) finance their national support schemes.

To reduce transaction costs for applicants and increase effectiveness of EU support, the establishment of a sufficiently coordinated process for the use of both CEF funding lines should be established. The most advisable options are a structural mixing of both funding lines (as part of dedicated synergy calls targeting project setups that combine generation and interconnector components), or coordinating the schedules and timelines of calls for proposals and work programs (including eligibility and selection criteria as well as application technicalities between funding lines). While providing a slightly lesser degree of efficiency gains compared to a structural mixing approach, the coordination of funding lines (where individual application and selection processes remain in place) avoids potential practical and legal problems in terms of unbundling rules between the main project promoters engaged in the transmission (mainly TSOs) and generation project components (private project developers).

Another option is the inclusion of a dedicated category for hybrid OWP as part of CEF Energy/PCIs, which would require a respective amendment of the revised TEN-E regulation. This would allow such projects to receive funding from CEF Energy/PCIs alone rather than having to combine funding from both CEF Energy support windows. In this case, hybrid OWPs would only have to apply for the PCI status without having to obtain the additional status as a c-b RES project, which would lower transaction costs. Given the relatively low funding volumes currently envisaged for the c-b RES funding line (currently €875 million until 2027, subject to final MFF decision), coordinating funding priorities may increase overall support effectiveness. For example, the c-b RES funding line could focus on funding for the preparation of preliminary and technical studies of hybrid OWPs, while CEF Energy/PCI focus on providing support for the actual implementation of such projects.

Renewables Financing Mechanism (Art. 33 Governance Regulation)

One instrument to support and ensure the RES target achievement at the European Union level is the "Union renewable energy financing mechanism," as provided in Article 33 of the Governance Regulation (and the implementing act defining its details). The mechanism's basic functioning is relatively simple (see Figure 5), Member States may choose to make voluntary financial contributions to the mechanism, which are pooled together as part of a dedicated budget line within the overall EU budget (potentially complemented by EU and private sector funds). The mechanism subsequently implements a competitive tender which determines support levels and allocates grants to RES projects in one or more host Member State(s) (or third countries), which choose to participate on a voluntary basis as well. The host Member State(s) transfer(s) the RES target statistics from these RES installations back to the mechanism, which then redistributes the RES statistics to the contributing Member States according to their share of financial contributions.

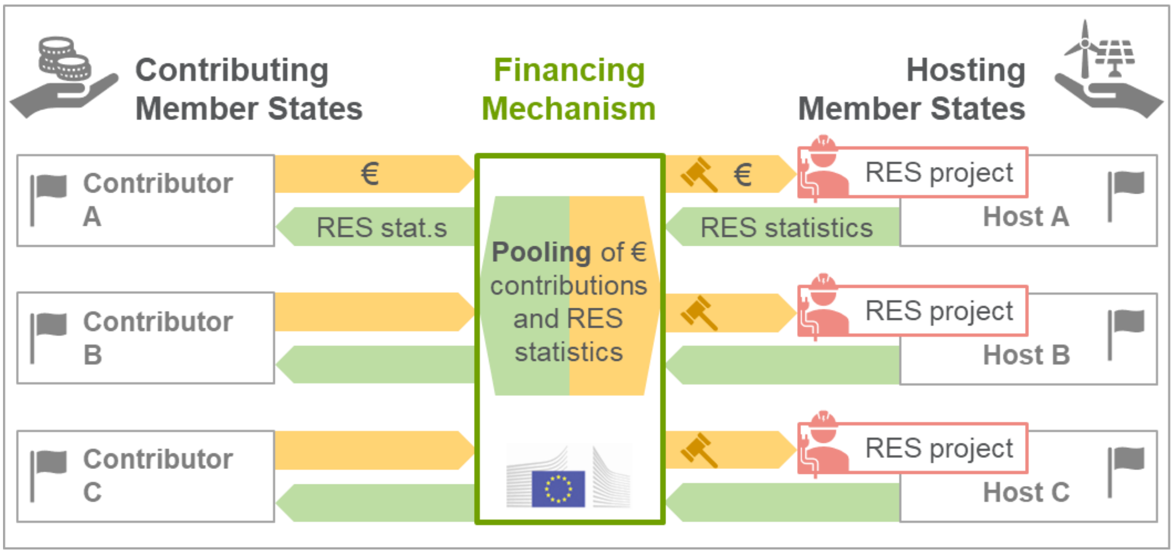


Figure 5. Basic structure of the Financing Mechanism *(source: Guidehouse)*

It is possible to use the Financing Mechanism to allocate support to (hybrid) OWPs. However, the allocation of support to (hybrid) OWPs through the mechanism may be unlikely, especially if project setups are simple or do not involve multiple Member States. In most cases, the use of a hosting country or joint support scheme is more straightforward. Multi-project hybrid offshore cooperation setups will likely remain the only conceivable use case. In particular, allocating support to (hybrid) OWPs could become relevant if additional EU funds are made available through the financing mechanism, e.g. to underline the strategic importance of hybrid offshore flagship projects or to increase the attractiveness of OBZ by reducing national support costs. In such scenarios, the mechanism may provide an existing framework under which Member States and EU funds can be combined to promote the deployment of offshore (hybrid) wind capacities. At the same time, the combination of EU funds with national funds may also be achieved through EU co-funding of national or joint support schemes (e.g. from CEF funds).

D) Integrated sequencing for the planning, tendering, and construction of hybrid assets

Linking OWP plans, interconnector planning, grid connection regulations, and standards is essential for facilitating and reducing the time schedules for the initial project planning for hybrid solutions in the North Sea. A key issue is the cross-border alignment of planning practices (including Maritime Spatial Planning), grid standards, and environmental permitting processes (including the required environmental impact assessments), which are crucial for cost-efficient planning, design development, cross-border agreements, and operational modes. It is recommended that for joint hybrid OWPs cross-border initiatives are established, encompassing the planning of OWPs, planning of onshore high voltage grid, planning of interconnections, common electrical requirements, and research programs (e.g. regarding the development of standards for offshore grid connections, development and planning of hybrid solutions and cross-border modalities for the development of energy hubs).

Regarding the phases covering financing, procurement, and construction, most of the rulesets already in place seem to be adequate and equipped with significant experiences from the oil & gas sector and from the offshore wind sector. In these areas, the market players do have a ruleset to follow and act effectively, with time and costs in focus. However, the operational and maintenance phases are mostly performed on an asset-by-asset operation with individual setups for nearly all offshore assets. Here a long-term focussed development towards a number of operational hubs can support the cost-efficient operation of an expanding number of OWPs’ capacity and hybrid solutions in the future.

The time plans of various conceivable project setups vary from 5–10 years related to the complexity of the configuration. A country-to-country connection is with the existing regulations complicated to establish. Voltage level, frequency synchronisation, and power quality are among the technical issues where Member State alignment can support a more efficient planning and development. Also the use of common EU or international standards instead of national standards on the high voltage grid level, on the design parameters for offshore installations can reduce the timespan for developing these solutions and ensure more standardised solutions with the long-term aim of cost-efficiency in manufacturing, construction, and operation and maintenance.

Several lessons have been learned through the development of interconnectors. While TSOs and Member States have pragmatically solved barriers, coordination is key. Most gain can be made on the permitting and planning side. However, there are precedents regarding matters that were previously considered unknowns or risks. These include uncertainly regarding legislating cross-border cables, revenue regimes, and planning OWPs and interconnector capacity (competition).

Conclusion

There is a variety of co-existing regimes for OWPs, none of which appears to outperform the others. However, when cooperating on offshore wind, especially with a view to joint (hybrid) OWPs, Member States will have to make up their minds as to what regime and its underlying rationales (e.g. market integration vs. lowering cost of capital) they want to apply.

Key to realising offshore cooperation includes the market arrangement issue, which has yet to be solved. By contrast, the cooperation software, the basic project setups, and the support schemes (including site selection, grid connection regime, form of support, and tender design) none appear to pose major design and implementation challenges. It is important to choose or design a coherent scheme which is suitable to the specific project setup. Coordinating these elements among the cooperation Member States (and its responsible parties in subordinate entities) is an underlying challenge to cooperation.

Proper CBA and CBCA are another issue for the deployment of joint (hybrid) OWPs. The different components and their assessments must be brought together, namely infrastructure and generation assets.

EU funds may serve to ease the cooperation efforts of Member States. If substantial and properly coordinated, the different sources (CEF energy and cross-border RES, EU RES financing mechanism, and EU recovery funds) may compensate for some of the transaction costs and cooperation impacts (e.g. offsetting lower producer rents in OBZ), and may add to the net benefit experienced by key players involved in offshore cooperation.

In terms of the integrated sequencing for the planning, tendering, and construction of hybrid assets, the lead times of various conceivable project setups vary considerably from 5–10 years related to the complexity of the configuration. While TSOs and Member States have pragmatically solved barriers, coordination is key for the proper sequencing.

Creating an integrated framework for financing joint (hybrid) OWPs is neither about standardising offshore schemes in NSEC countries nor about overly complex and sophisticated support scheme designs. It is about understanding the benefits of specific cooperation projects, options to make sure all involved countries benefit from them, and about the proper coordination of the framework elements in the involved Member States.

1. Introduction

The development of large-scale offshore wind projects is a precondition for achieving the long-term goal to decarbonise energy systems in the EU. At the end of 2019, the installed capacity of offshore wind totalled approximately 12 GW (and ~10 GW in the UK).[22] In its scenario for reaching climate neutrality by 2050 the European Commission estimates offshore wind capacities between 230 GW and 450 GW to be installed in European waters.[23] Almost three-quarters of these capacities are likely be in the North Sea and Baltic Sea.

Such large-scale development of offshore wind requires significant investments in generation assets and the grid and coordination among EU Member States and the joint development of cross-border offshore projects. Coordinated regional development has the potential to reduce costs (especially when offshore wind farms move further away from the shore and induce higher costs for grid connection) and limit environmental impacts compared to purely national approaches. In this context, hybrid offshore wind projects (OWPs) provide potential for more cost-effective offshore development and yield further benefits for the connected energy systems. Hybrid OWPs are projects where the development and implementation of offshore wind and interconnection capacity is combined. The hybrid asset is infrastructure with the dual functionality of internal transmission and interconnection. The scope of this report focusses on OWPs that are built as a cooperation project and that may (but do not necessarily have to) include an interconnector functionality.

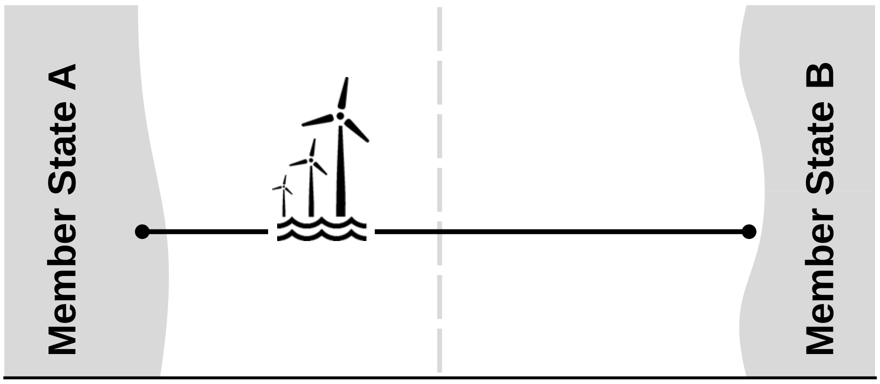


Figure 1-1. Basic setup of hybrid OWP *(Source: Guidehouse)*

Member State cooperation and the potential use of hybrid OWPs to take advantage of the North Seas' wind-power potential has the North Seas Energy Cooperation's (NSEC's) political support. NSEC aims to strengthen cooperation on offshore energy and improve conditions for the development of offshore wind energy in the North Sea. With these goals, NSEC hopes to enable a sustainable, secure, and affordable energy supply in the region. NSEC decided to explicitly facilitate hybrid projects through a new, project-based support group (hybrid and joint projects), which works on the already identified potential hybrid and joint projects but is not limited to these. The support group on "support framework and finance" examines the tendering and financing of joint cross-border offshore projects, including new financing opportunities under the new Connecting Europe Facility (CEF) and the Union Renewable Energy Financing mechanism. The European Commission supports NSEC's work. The 6 July 2020 Joint Statement of North Seas Countries and the European Commission

[22] WindEurope, 2020. Offshore Wind in Europe, Key trends and statistics 2019. https://windeurope.org/wp-content/uploads/files/about-wind/statistics/WindEurope-Annual-Offshore-Statistics-2019.pdf

[23] European Commission, 2018. In-depth analysis in support of the Commission Communication COM(2018) 773. A Clean Planet for all. A European long-term strategic vision for a prosperous, modern, competitive and climate neutral economy. https://ec.europa.eu/clima/sites/clima/files/docs/pages/com_2018_733_analysis_in_support_en_0.pdf

reiterates the potential of RES cooperation and of hybrid OWPs to “to accelerate the cost-efficient deployment of offshore wind energy.”[24]

Despite the benefits of and initial political support for hybrid projects, their development has been limited (so far only Kriegers Flak has been realised). This is largely due to the complexities of planning, tendering, and financing hybrid projects, which requires substantial coordination between the different assets (generation, connection to shore, interconnector), the actors involved (project developers, transmission system operators [TSOs], Member States), and an integrated approach for cost-benefit assessment (CBA) and cost sharing. Against this background, the objective of this report is to summarise the current state of play of the financing and cost recovery of the various hybrid project (hybrid asset) components in the NSEC countries and, based on this overview, to develop recommendations for an integrated framework for the financing of joint (hybrid) OWPs.

There are several key challenges that such an integrated framework needs to address:

- **Coordination of regulatory regimes and applicable rules between countries:** The regulatory regimes and support schemes for financing all three components differ between NSEC countries, exponentially increasing the complexity for offshore cooperation projects and specifically with a view to hybrid OWPs. While the general alignment of regimes might be preferable on the long-term, project-specific alignment might be a more realistic option on the short term (e.g. joint project tenders or Hybrid Asset Network Support Agreements).

- **Providing guidance and standardised design options to overcome the** limited **experience with cross-border (joint or opened) support schemes and cooperation mechanisms**. With few exceptions (none of them offshore), support schemes for RES generation assets have a national scope. The use of cooperation mechanisms has been hampered by the initial transaction costs for setting up such mechanisms and negotiating a fair CBA between Member States.

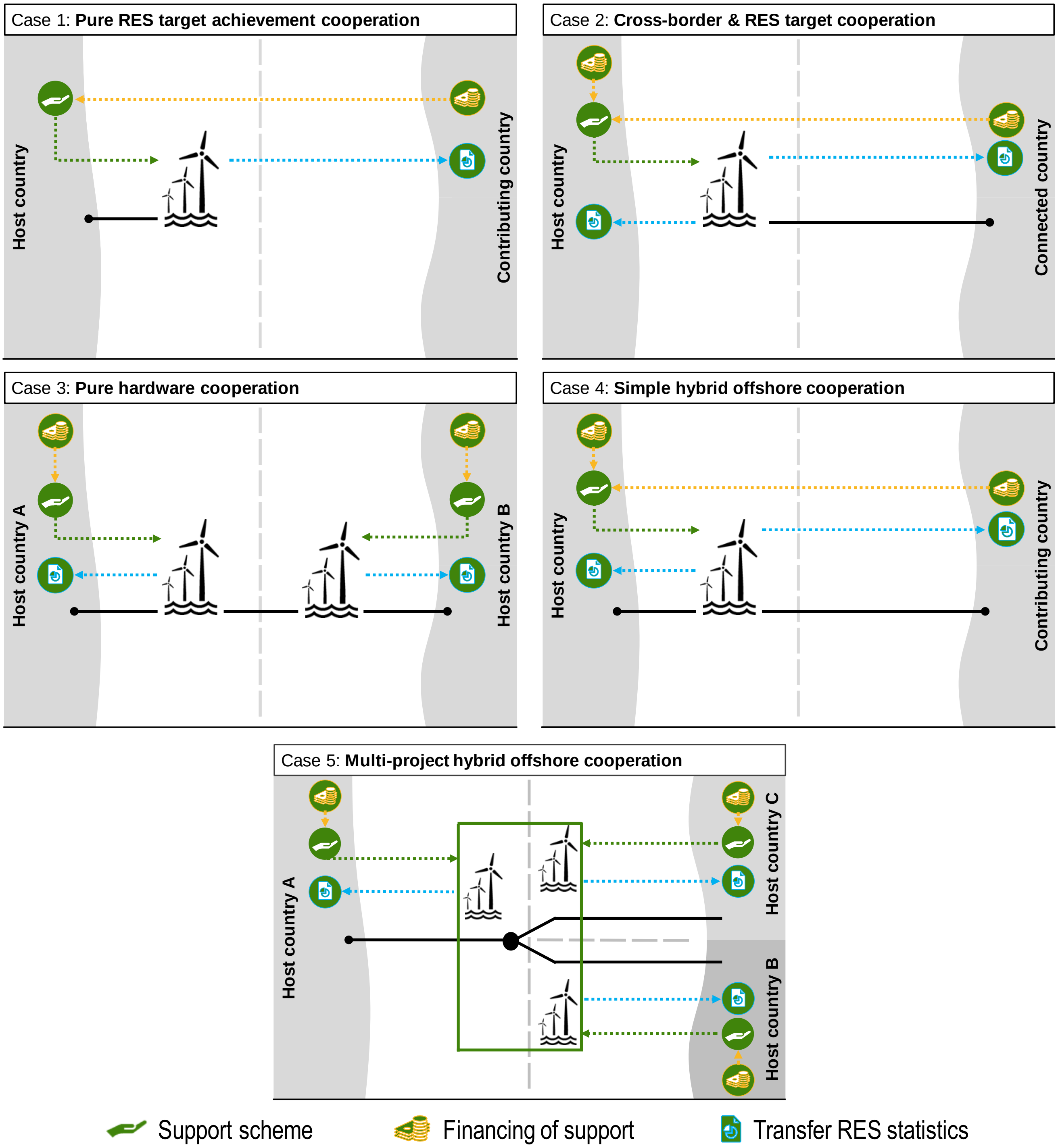
- **Providing an integrated approach for joint hybrid OWPs for the CBA and cross-border cost allocation (CBCA):** Costs and benefits must be properly identified and a CBCA needs to be implemented that allows to turn the social-welfare benefit of joint (hybrid) OWPs into a benefit for all participating parties. Otherwise, cooperation will be blocked by an actor who has an overall loss as a result of the project. At the same time, the complexity of this assessment and allocation needs to be kept at a manageable level or it will become (or remain) a barrier to cooperation. For hybrid OWPs, the CBCA must happen for the generation assets and for the transmission assets, which in turn have established processes to determine the costs and benefits and their allocation to the involved parties. Different existing approaches for need to be coordinated in the case of joint hybrid OWPs.

- **Adding EU funds to the cooperation to increase the business case for the cooperating partners:** While EU CEF funding has focussed on interconnectors, a new funding line for cross-border RES projects is introduced in the new CEF. The different funding opportunities (including the EU RES financing mechanism) need to be properly coordinated to ensure access to funding while avoiding larger subsidies than necessary.

- **Coordination between hybrid offshore project components:** Various elements need to be permitted, built, financed (generation, transmission, interconnections). Already on national level (i.e. excluding interconnectors) this induces high complexity for offshore projects. This also requires an integrated sequencing for the planning, tendering, and construction of hybrid assets. Different lead times and planning horizons can lead to substantial delays and increased costs in the realisation of joint (hybrid) OWPs. An integrated framework should align the duration and sequencing of the different asset development procedures.

[24] Joint Statement of North Seas Countries and the European Commission of 6 July 2020, available at: https://www.bmwi.de/Redaktion/DE/Downloads/M-O/nsec-joint-statement.pdf?__blob=publicationFile&v=4

The report develops recommendations to address these challenges. There are manifold options to setup joint (hybrid) OWPs. We identify five likely project setups, including and excluding interconnector functionality, to reduce the complexity of options and to make recommendations as tangible as possible.[25] These cases include not only the hardware setup but also the cooperation software:



[25] Note that the cooperation cases build on the ones presented in Roland Berger 2018: Hybrid Projects. How to reduce costs and space for offshore developments. Available at: https://ec.europa.eu/energy/studies/hybrid-projects-how-reduce-costs-and-space-offshore-developments_
en?redir=1.

Case 1 RES target achievement: In this setup, no interconnector functionality is part of the cooperation project and the OWP is located in the Member State it is connected to. The host Member State support scheme is used (with or without actual support costs). This case represents a joint project according to Article 9 of the RED II. The contributing country pays a defined amount per energy to the host country (for instance, part of the support costs) to receive a corresponding share of the RES statistics resulting from the OWP electricity production.

Case 2: Cross-border and RES target achievement: In this setup the OWP is located outside of the exclusive economic zone (EEZ) of the Member State it is connected to. The host country's support scheme is used (with or without support costs) and the host country transfers parts of RES statistics to the Member State the OWP is connected to, to compensate integration costs.

Case 3: Hybrid - hardware-only: In this setup, the project is a hybrid project, it includes an interconnector functionality. One OWP is located in each of two EEZs and connected to their respective shores while being connected to each other. Each Member State uses their respective support scheme and keeps the RES statistics produced from the OWPs in their EEZ.

Case 4: Hybrid - hardware and software: This setup includes interconnector functionality as well. One OWP is located in Member State A (host country). The host country's support scheme is applied, but the two Member States the OWP is connected to finance the support. In this case, the RES statistics are transferred from the host Member State to the contributing Member State, according to the agreed share.

Case 5: Multi-project hybrid - hardware and software: This setup would include an interconnector functionality and could include, for instance, several OWPs connected to the interconnector via a hub, one in each Member State (i.e. A, B, and C). In this case, a new support scheme may be implemented (i.e. according to Article 13 of the RED II), which would be funded by all three MS. The support could be auctioned centrally by a single dedicated authority or by a cooperation of the involved auction authorities (i.e. energy agencies or regulators). The RES statistics would be transferred according to share of support scheme payments or any other CBCA agreement implemented by the involved parties.

The report covers a variety of challenges and thus numerous topics. It is structured as follows: Task 1 (section 2) provides an overview of financing and cost recovery of generation support (section 2.1), connections to shore (section 2.2), and interconnectors in NSEC countries (section 2.3). The focus of the analysis are NSEC countries and the UK, for which the current status and ongoing developments are presented. The analysis allows to formulate recommendations for financing and cost recovery of hybrid projects in Task 2 (section 3).

Task 2 provides analysis of and recommendations on an integrated framework for the financing of joint (hybrid) OWPs. The recommendations are developed primarily with a view to NSEC countries and cooperation among them. These recommendations are also applicable to other offshore regions, such as the Baltic or Mediterranean seas. Section 3.1 discusses approaches to cooperation and support scheme design. This section discusses the impacts of different market arrangements on the financing of hybrid offshore projects, namely the home zone (HZ) and the offshore bidding zone (OBZ) solutions. Although this aspect is not the core of this report, it has major impacts on the investment framework for OWPs. We discuss the cooperation software and a set of typical OWP setups. Subsequently, we detail the recommended support scheme design and, as part of the support scheme, include in this the process for site selection, the grid connection regime, the form of support (and related financing issues), and the tender design. Finally, this section elaborates on the options to include Power-to-X (PtX) into the project setup and discusses whether and how any of the previous recommendations change if PtX solutions are included.

Section 3.2 addresses a key barrier to the realisation of hybrid offshore projects: the proper analysis and subsequent reallocation of costs and benefits resulting from hybrid offshore projects. It builds on existing approaches and advances them to capture the specific nature of hybrid offshore projects, i.e. the combination of generation and transmission assets and the cooperation aspects around financing support payments and RES target achievement. We apply the developed recommendations to a set of case studies in section 3.2.4).

Section 3.3 includes recommendations on the use of CEF and the Renewables Financing Mechanism for hybrid offshore projects. CEF funding lines for infrastructure and cross-border RES projects are particularly suited to ease planning and permitting for such projects and they provide funding for technical support as well as grants for works. This support, if made accessible for hybrid offshore projects, may improve the incentives for Member States, TSOs, and project developers to realise large-scale projects.

Section 3.4 presents timelines for different hybrid configurations for offshore wind solutions and the transmission to the land-based, high voltage transmission systems based on the processes for development, planning, permitting, and construction of offshore infrastructure and energy solutions. Elements covered in this task include maritime spatial planning, asset sizing, technical specification, request for funding support, the CBA and CBCA decision, as well as the construction and commissioning activities.

This report covers a wide range of elements regarding the financing of (hybrid) OWPs. Section 4 presents our main conclusions.

2. Task 1 – Overview of the current financing and cost recovery of generation support, connections to shore, and interconnectors in NSEC countries

Task 1 summarises financing and cost recovery of generation support, connections to shore, and interconnectors in NSEC countries. The analysis focusses on NSEC countries and the UK, for which the current status and ongoing developments are presented. The analysis helps formulate recommendations for financing and cost recovery of hybrid projects in Task 2.

2.1 Tender design features, financing, and cost recovery of OWP generation support in NSEC countries

2.1.1 Introduction

This section investigates financing and cost recovery mechanisms for offshore renewable energy, i.e. offshore wind farms. Within NSEC countries and the UK, multiple countries have established offshore wind markets and have set development targets for 2030. Figure 2-1 presents the 2030 offshore wind targets of NSEC countries and the UK, as well as the installed capacity at the end of 2019. The figure shows the delta in capacity still required to meet the 2030 targets. Note that Norway and Sweden currently have no 2030 targets for offshore wind in place.

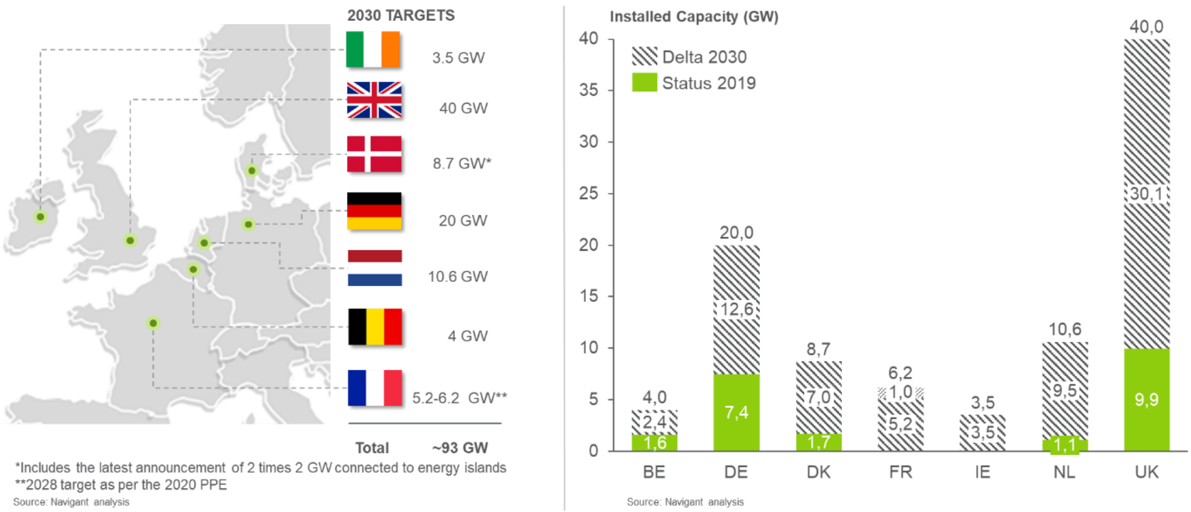


Figure 2-1. Offshore wind targets in NSEC countries and UK and installed offshore wind capacity vs. delta as per end 2019. *Source: Guidehouse analysis*

The 2030 targets are a significant step forward towards an accelerated scale up of offshore wind capacity towards 2050. Figure 2-2 shows the current, planned, and projected offshore wind capacity for NSEC countries and the UK. At the end of 2019, the installed capacity of offshore wind totalled approximately 12 GW (and 10 GW in the UK).[26] The respective cumulative capacity of 2030 targets adds up to approximately 93 GW in 2030 in the NSEC countries and the UK (see Figure 2-1). In 2018, the European Commission presented its “Clean Planet for all” vision, which included 230 GW to 450 GW of offshore wind capacity for the EU27 and the UK by 2050.[27] The highest level of this range was

[26] WindEurope, 2020. Offshore Wind in Europe, Key trends and statistics 2019. https://windeurope.org/wp-content/uploads/files/about-wind/statistics/WindEurope-Annual-Offshore-Statistics-2019.pdf

[27] European Commission, 2018. In-depth analysis in support on the COM(2018) 773: A Clean Planet for all - A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy. https://ec.europa.eu/knowledge4policy/publication/depth-analysis-support-com2018-773-clean-planet-all-european-strategic-long-term-vision_en

used by WindEurope to develop a 2050 vision with a higher granularity on country level.[28] It allocated 77% of all offshore wind capacity to NSEC countries and the UK, resulting in a total capacity of 346 GW (of which approximately 80 GW allocated to the UK). Using the lower range of the Clean Planet for all vision and the same share for NSEC countries and the UK results in a total capacity of 177 GW (of which approximately 41 GW allocated to the UK). Regardless of the scenario, a massive scale up of offshore wind is required between 2030 and 2050, resulting in an average rollout rate of 4 GW/yr-13 GW/yr in NSEC countries and the UK combined. The lower end of the rollout rate range (4 GW/yr) is less probable as the required average rollout rate between 2019 and 2030 already amounts to 6 GW/yr.

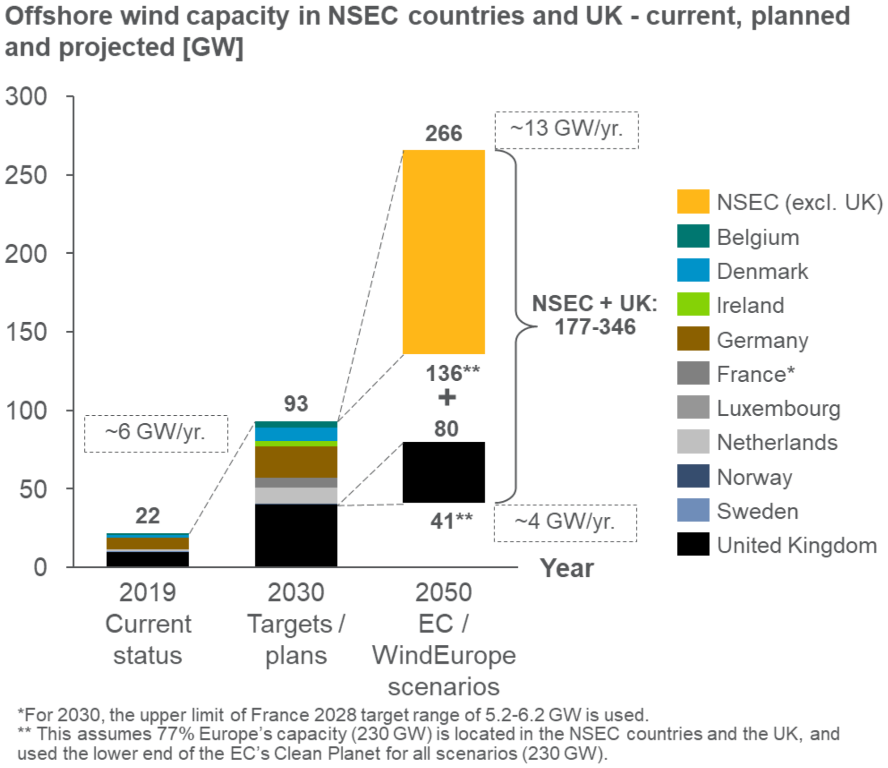


Figure 2-2. Offshore wind capacity in NSEC countries and UK – current and projected. *(Source: Guidehouse analysis)*

Regardless of whether the installed capacity is aiming for a modest 177 GW in 2050 or the ambitious vision of 346 GW in the NSEC countries and the UK, substantial investments are needed and annual investments need to be accelerated. When estimating the total investment need in euros, there are various factors inducing uncertainty, including:

- Final installed capacities. The range in the estimated capacity in 2050 (Figure 2-2) already accounts for a factor of 2 in the investment uncertainty.
- Year of investment and inflation rates.
- Raw material prices and labour costs.
- Location of wind farms. Wind farms located further offshore are usually more expensive than the same wind farm located closer to the shore. In addition to more expensive foundations, the cable distance is a large driver behind the total CAPEX.

[28] WindEurope, 2019. Our energy, our future. How offshore wind will help Europe go carbon-neutral. https://windeurope.org/wp-content/uploads/files/about-wind/reports/WindEurope-Our-Energy-Our-Future.pdf

- Connection regime, radial vs. coordinated, meshed, hybrid approach. We have already shown that a coordinated meshed approach can have significant cost reductions compared to a radial connection approach.[29,30] This is part of the philosophy behind hybrid assets.

- It matters how investment is defined and if the cost of additional components is included, such as OPEX, decommissioning, onshore grid capacity reinforcements, and storage/flexibility options.

- Development of learning curves and technology maturity (including turbine sizes, capacity factor, losses, foundation types, AC/DC, feed-in requirements) combined with economies of scale can have a significant impact on the total investment need.

Taking these uncertainty drivers into account, a high level estimate of the total investment need to realise the offshore capacity in 2050 in the scenarios for the NSEC countries and the UK is €360-€750 billion, of which €200-€500 billion is for the grid part (transmission and interconnection) and €160-€250 billion for the generation part. The UK would account for approximately 23% of this range according to their share in offshore wind farm capacity.[31] This estimate is calculated on transmission CAPEX ranges of €1.1-€1.6 billion/GW,[32,33,34] and €0.8-€1.3 billion/GW for the generation part.[35,36,37] This estimate is in the same range as some other estimates, such as the number of €789 billion for the offshore investment in the EU27 and €995 billion in the EU28 of the JRC[38,39] and the investments needs estimate by WindEurope to reach 450 GW in the EU and 212 GW in the North Sea by 2050.[40]

This investment need for offshore wind farms is in the NSEC countries and the UK contributes to the need for support payments, which have developed recently towards lower support levels. Figure 2-3 presents the evolution of the tender prices for offshore wind farms in the relevant NSEC countries and the UK ranked following the year of commissioning. An overall downward trend can be observed in tender prices. Important to note is the relation between the grid delivery model and the bid levels, which determines whether the grid connection falls under the responsibility of the developer and therefore is included in the bid price. In recent years, tenders in the Netherlands and Germany have even resulted in zero tender prices as they excluded the grid connection costs (a more detailed assessment of grid connection regimes and responsibilities per country is given in Figure 2-16 in

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[29] EC, 2014. Study of the Benefits of a Meshed Offshore Grid in Northern Seas Region. https://ec.europa.eu/energy/sites/ener/files/documents/2014_nsog_report.pdf

[30] EC, 2018. Study on regulatory matters concerning the development of the North Sea offshore energy potential. https://op.europa.eu/en/publication-detail/-/publication/cf1b6dd1-05f0-11e6-b713-01aa75ed71a1

[31] Investments for NSEC only (excluding UK) would be a total of approximately 275-575 bn EUR. Of which 155-385 bn EUR would cover the grid infrastructure (transmission and interconnection) and 125-195 bn EUR would cover the generation assets.

[32] Ecofys, 2017. Translate COP21 - 2045 outlook and implications for offshore wind in the North Seas. https://northseawindpowerhub.eu/wp-content/uploads/2017/10/Translate-COP21-Public-report-July2017-final.pdf

[33] DNV GL, 2019. Cost of offshore transmission. https://www.tennet.eu/fileadmin/user_upload/Company/News/Dutch/2019/20190624_DNV_GL_Comparison_Offshore_Transmission_update_French_projects.pdf

[34] Offshore Wind Programme Board, 2016. Transmission Costsfor Offshore Wind. https://ore.catapult.org.uk/app/uploads/2018/02/Transmission-Costs-for-Offshore-Wind.pdf

[35] Fraunhofer ISE, 2013. Levelised Cost of Renewable Energy (Stromgestehungskosten Erneuerbare Energien). https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/DE2013_ISE_Studie_Stromgestehungskosten_Erneuerbare_Energien.pdf

[36] Ecofys, 2016. Prices and costs of EU energy. https://ec.europa.eu/energy/studies/prices-and-costs-eu-energy-%E2%80%93-ecofys-bv-study_en

[37] IEA, 2019. Offshore wind outlook 2019. https://www.iea.org/reports/offshore-wind-outlook-2019

[38] JRC, 2018. Deployment Scenarios for Low Carbon Energy Technologies. Deliverable D4.7 for the Low Carbon Energy Observatory (LCEO). https://publications.jrc.ec.europa.eu/repository/bitstream/JRC112915/jrc112915_lceo_d4.7.pdf

[39] JRC, 2020. Technology Development Report Wind Energy. https://publications.jrc.ec.europa.eu/repository/bitstream/JRC118315/jrc118315_1.pdf

[40] WindEurope, 2019. Our Energy Future. https://windeurope.org/wp-content/uploads/files/about-wind/reports/WindEurope-Our-Energy-Our-Future.pdf

section 2.2.2.1). As a result, other criteria than price may be used as evaluation of winning bids in a tender.

The following sections summarise ongoing developments per country. Section 2.1.2 analyses characteristics of relevant schemes for offshore wind from the past 5 years, including any concrete current and upcoming schemes in NSEC countries and the UK. This results in a comparative overview table of tender scheme design features. Section 2.1.3 provides an overview of any ongoing developments of tender schemes for offshore wind in NSEC countries and the UK.

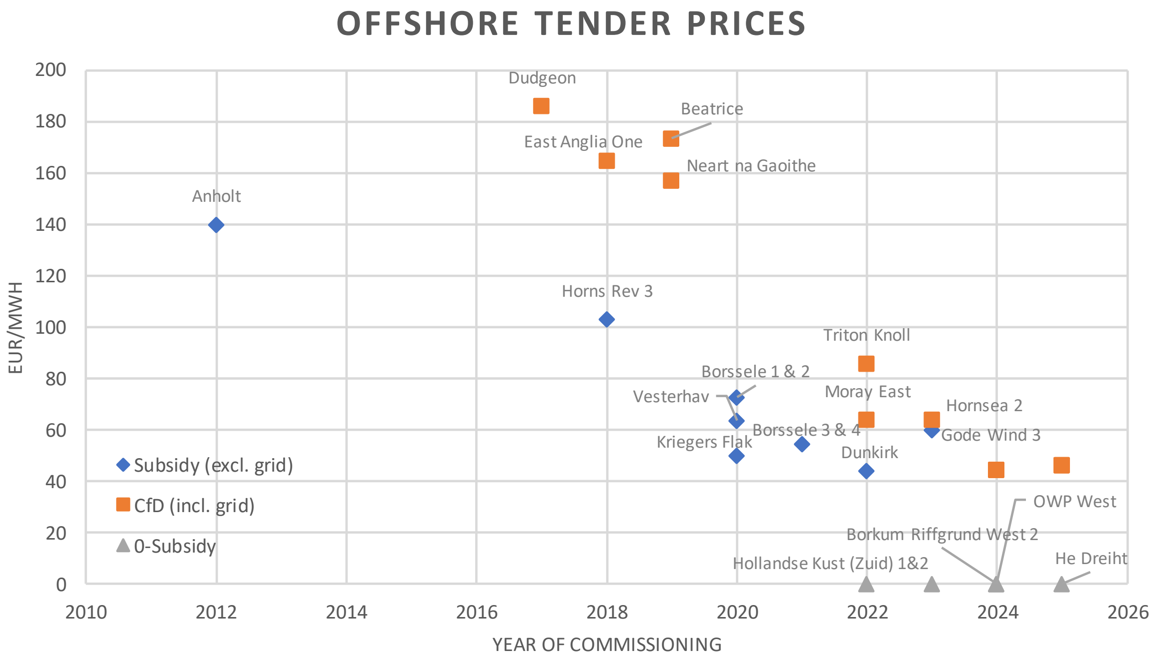

Figure 2-3. Offshore tender prices in NL, UK, DK and DE following year of commissioning.
(Source: Guidehouse analysis)

2.1.2 Overview of past and current support schemes

NSEC countries with an established offshore market are Belgium, Denmark, France, Germany, and the Netherlands. The UK is also an important offshore player in the North Sea area, it has the highest capacity installed and by far the most ambitious planning for 2030. These countries are adopting different tender schemes to support offshore wind developments. Each country has implemented different design choices for their tender scheme, each with their advantages and disadvantages. Design options within tender schemes effectively distribute the risk between the government (and TSOs) and project developers.[41] The focus of this section are any tender schemes for offshore wind applied during the past 5 years and any concrete upcoming schemes in these countries. Section 2.1.3 summarises ongoing developments in the different NSEC countries and the UK.

Table 2-1 displays the characteristics of the tender schemes for offshore wind in the above countries. The characteristics are identified around three main themes:

(1) The process for site selection and pre-investigation: The responsible party for offshore wind farms site selection and pre-investigation can differ between a state body or a commercial developer. The process for site selection will determine ties in with auction design features for selection

[41] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf

mechanism and pricing rules. A tender scheme refers to the entire legislation (including details on the grid connection). Support is then allocated through a selection mechanism.

(2) Support scheme and auction design features: The selection process for the allocation of support within a tender includes various design features that each have their advantages and disadvantages and often imply trade-offs. Table 2-1 compares the following auction design features for the applicable NSEC countries and the UK:

- **Allocation process** determines how support is allocated, for example, through a competitive auction or negotiation.
- **Pricing mechanism** details how the clearing price for support is determined in an auction round, for example, pay-as-bid or pay-as-clear.
- **Technology-specific or multi-technology process** presents the setting in which support for offshore wind is allocated and if offshore wind is competing with other technologies.
- **Form of support** specifies what type of support is paid (which has impacts on the actual amounts of support), for example through a fixed feed-in tariff, a fixed premium, a sliding premium or CfD, or potentially through investment aid.
- **Duration of support** sets out the criteria to determine the duration of support payments to a developer. The duration of support links with the duration of the concession obtained by the developer.
- **Bid and completion bond requirements** set the stage for the bidding process, for example, through bid-bonds to prevent speculative bids.
- **Financial and material pre-qualification requirements** can be both financial and technical and can be used to assess the capacity to deliver of developers participating in a tender to ensure timely project realisation.
- **Delivery rules** can be used to ensure timely project development by specifying project realisation timelines after the award of support, supplemented with potential penalties for project delays or non-delivery.
- **Innovation requirements** can be part of non-price selection criteria in a tender scheme.

(3) The financing and cost recovery of the support granted: Lastly the support payments to offshore wind farms need to be paid out by the responsible entity and recovered through a cost recovery mechanism. The financing and cost recovery process is detailed for the respective countries.

The comparison table starts with an overview of the names and wind capacity volumes per round.

Table 2-1. Comparative overview of wind support schemes in NSEC countries and the UK. *Rounds are mentioned based on the tender year.*

	Belgium	Denmark	France	Germany	Netherlands	United Kingdom
Name Scheme	*Previous:* First offshore wind phase *Upcoming:* Second offshore wind phase (expected 2023 – new scheme)	*Prior to 2016:* Horns Rev 2 Rødsand 2 (2 tenders) Anholt Horns Rev 3 *From 2016:* Nearshore areas (2016) Kriegers Flak (2016) Open door round (2019) *Upcoming:* Thor (2021)	*Prior to 2016:* First round (2011) Second round (2013) *From 2016:* Third round (2016) (Dunkirk) *Upcoming:* Fourth round expected in 2020	*Previous:* EEG 2017: Transition period with existing projects (2017-2018) *Upcoming:* Central model (from 2021)	*Previous:* Borssele I and II (2016) Borssele III and IV (2016) Hollandse Kust (zuid) I and II (2017) Borssele V (2018) – Innovation site Hollandse Kust (zuid) III and IV (2019) Hollandse Kust (noord) IV (2020) - *In progress* *Upcoming:* Hollandse Kust (west) VI (2021) Ten Noorden van de Waddeneilanden (2022) Ijmuiden Ver (2023-2026)	*Previous:* AR1 (2015), AR2 (2017), AR3 (2019) for pot 2-technologies including offshore wind *Upcoming:* AR 4 expected in 2021

	Belgium	Denmark	France	Germany	Netherlands	United Kingdom
Offshore wind volumes in schemes	*Previous:* First offshore wind phase: 2,300 MW by 2020 *Upcoming:* Second offshore wind phase ~2 GW	*From 2016:* Nearshore areas (2016): 350 MW Kriegers Flak (2016): 600 MW *Upcoming:* Thor (2021): 800 MW-1,000 MW	*Previous:* First round (2011) Second round (2013) Third round (2016) Combined ~3.5GW awarded with commissioning between 2022-2026 *Upcoming:* Fourth round (2020): 1 GW	*Previous:* Transition period (EEG) 2017-2018: 3.1 GW *Upcoming:* Central model starting 2021: 700 MW-900 MW annually	*Previous:* Borssele I and II (2016): 752 MW Borssele III and IV (2016): 731,5 MW Hollandse Kust (zuid) I and II (2017): 740 MW Borssele V (2018): 19 MW Hollandse Kust (zuid) III and IV (2019): 760 MW *Upcoming:* Hollandse Kust (noord) IV (2019): 700 MW - 760 MW	*Previous:* AR1 (2015): 1,162 MW AR2 (2017): 3,196 MW AR3 (2019): 5,466 MW
(1) Site-selection process	First offshore phase: zone pre-defined by the government, developers apply for domain concessions Second offshore phase: sites pre-defined by the government	Sites pre-defined by the government except for nearshore tender and open door procedure	Sites pre-defined by the government	Selection by developers until 2018 within specific zones to consider constraints in the onshore grid Sites pre-defined by the government from 2021 onwards	Sites pre-defined by the government	Selection by developers (i.e. open locations) in zones allocated the Crown Estate

	Belgium	Denmark	France	Germany	Netherlands	United Kingdom
(2) Allocation process	First offshore phase: negotiation on support level - developers apply for a domain concession within zone after which the support level is negotiated Second offshore phase: auction	Open door procedure: unsolicited application for licence for preliminary investigations Nearshore: auction with negotiation across 6 predefined areas *Upcoming*: Auction (with pre-qualification and negotiation)	First-Second round: call for tender Since third round: auctions (competitive dialogue)	Auction	Auction	Auction
(2) Pricing rule	First offshore phase: support negotiated after domain concession (e.g. Based on LCOE) Second offshore phase: to be decided through Royal Decree (see section 2.1.3.1)	Open door procedure: fixed premium (25 øre/kWh; if the market price 58 øre/kWh the subsidy will be reduced accordingly) *Nearshore/previous and upcoming*: Pay-as-bid	Pay-as-bid (price and qualitative criteria apply)	Pay-as-bid	Pay-as-bid; Since 2017, zero subsidy bids are evaluated based on several qualitative criteria (e.g. experience of project developer)	Pay-as-clear
(2) Technology-specific or multi-technology process	Technology-specific Second offshore phase: site specific, technology neutral for offshore technologies	Technology neutral for onshore/open-door offshore wind and solar (2018/2019) Nearshore: multi-site (six sites) Centralised tenders: Technology-specific	Technology-specific	Technology-specific	Technology-specific	Multi-technology as part of pot 2 (“less established technologies”)

	Belgium	Denmark	France	Germany	Netherlands	United Kingdom
(2) **Form of support**	First offshore phase: feed-in premium negotiated after domain concession is granted and Quota system: Exact mechanism to calculate the support have evolved over time. Projects receive green certificates from the federal regulator (CREG) per MWh. and can sell them to the TSO Elia Second offshore phase: to be decided through Royal Decree (see section 2.1.3.1)	Open-door: fixed premium Nearshore: hourly feed-in premium Horns Rev 3 (2015) and Kriegers Flak (2016): CfD Thor: capped CFD (see section 2.1.3.2)	*Prior to 2016:* feed-in tariff *Since third round 2016:* (Dunkirk): Monthly Sliding feed-in premium Feed-in tariff through power purchase agreement can still be adopted but has not been adopted in practice	Monthly, sliding feed-in premium	Yearly, sliding feed-in premium	Hourly, Contract for Difference
(2) **Duration of support**	First offshore phase: 20 years (license for operation given for 20 years[42]) Second offshore phase: to be decided through Royal Decree (see section 2.1.3.1)	Nearshore and Horns Rev 3: 50 000 full load hours (FLH) Kriegers Flak: 30 TWh Thor: 20 years (operational license usually given for 25-year period, with an option to extend)	20 years (authorisation to use maritime public domain cannot exceed 40 years)	20 years (25 years operation period allowed[43])	15 years (permit duration 30 years – 40 years is to be approved by parliament)	15 years (permit duration 60 years for Lease round 3)

[42] CMS, 2017. Offshore Wind Energy Law and Regulation in Belgium. https://cms.law/en/int/expert-guides/cms-expert-guide-to-offshore-wind-in-northern-europe/belgium

[43] Federal Ministry of Economics and Technology (Germany) , 2015. Offshore wind energy. https://www.bmwi.de/Redaktion/EN/Publikationen/offshore-wind-energy.pdf?__blob=publicationFile&v=3

		Belgium	Denmark	France	Germany	Netherlands	United Kingdom
(2)	**Bid and completion bond requirements**	Second offshore phase: to be decided through Royal Decree (see section 2.1.3.1)	Financial guarantee of DKK 100 million (€13 million) Thor: N/A	N/A	Financial guarantee in the form of a bid bond of €100 per kW (until 2018) and €200 per kW (from 2021)	Post-award financial guarantee of €35 million applies (reservation fee of site after permit award)	N/A
(2)	**Financial and material pre-qualification requirements**	Second offshore phase: to be decided through Royal Decree (see section 2.1.3.1)	Technical and financial bidder qualification requirements apply	Technical and financial bidder qualification requirements apply	*Previous:* auction is only open to projects that are already under development (§ 26 WindSeeG)	Yes, project plan, wind report, operational calculation.	Yes, Crown Estate Agreement for lease of site, planning permission and development consent order
(2)	**Delivery rules**	Second offshore phase: to be decided through Royal Decree (see section 2.1.3.1)	Production eligible for support will be reduced in decrements over set time periods in case of delays	Shortened duration of support in case of late delivery. Penalty capped at €500 per kW if project not implemented without valid reason	Realisation period from grid connection completion: 18 months. Non-delivery may lead to withdrawal of the licence and full or partial confiscation of the bid bond.	Realisation period of 5 years with monthly delayed delivery penalties, bank guarantee will be confiscated in case of non-delivery	Contracts are awarded for delivery in a particular year. Delayed delivery leads to Long Stop of additional 12-24 months after which contract might be terminated. Non-Delivery Disincentive: Non-delivery leads to exclusion for any project at the same location and from future auctions for 24 months [44]
(2)	**Innovation requirements**	N/A	N/A	Dedicated floating offshore wind tenders are planned in France (see section 2.1.3.3)	N/A	Dedicated offshore wind innovation rounds, e.g. Borsselle V Hollandse Kust (noord) IV: developers are scored on: demonstration of innovation, Sharing of knowledge of innovation	Dedicated minimum capacity caps for new technologies including floating wind

[44] Department for Business, Energy and Industrial Strategy, 2019. Frequently Asked Questions. https://www.cfdallocationround.uk/faqs

	Belgium	Denmark	France	Germany	Netherlands	United Kingdom
(3) Entity in charge of paying out support	The federal electricity regulatory authority (CREG) is responsible for allocating green certificates. The TSO Elia is obliged to buy the green certificates.	Danish State	EDF (through PPA or CfD)	Transmission grid operators (TenneT and 50Hertz)	Netherlands Enterprise Agency (RVO) as executive agency of the Dutch Ministry of Economic Affairs and Climate.	Low Carbon Contracts Company (LCCC)
(3) Cost recovery of support granted	Financed by consumers via surcharge on electricity bill	Financed by consumers via surcharge on electricity bill (PSO levy) The PSO levy being phased out between 2017-2021 to shift the financing of to the State Budget[45]	Financed by consumers via surcharge on electricity bill	Financed by consumers via surcharge on electricity bill (EEG-Umlage)	Financed by consumers via surcharge on electricity bill (ODE)	Financed from the state budget raised through end-consumer levies
References	Hogan Lovells, 2019 IEA RETD, 2017 Navigant, 2019a CREG, 2018	Hogan Lovells, 2019 AURES DK, 2019 AURES Thor, 2020 IEA RETD, 2017 Navigant, 2019a DEA, 2020a-20202b EC, 2016	Hogan Lovells, 2019 IEA RETD, 2017 Navigant, 2019a MTES, 2019 OffshoreWindBiz, 2018	Hogan Lovells, 2019 AURES DE, 2019 IEA RETD, 2017 Navigant, 2019a	Hogan Lovells, 2019 AURES NL, 2019 IEA RETD, 2017 Navigant, 2019a Navigant, 2019b RVO, 2020a-b	Hogan Lovells, 2019 AURES UK, 2019 IEA RETD, 2017 Navigant, 2019a

[45] Danish Ministry of Climate, Energy and Utilities, 2019. Denmark's Integrated National Energy and Climate Plan. https://ec.europa.eu/energy/sites/ener/files/documents/dk_final_necp_main_en.pdf

2.1.3 Overview of support schemes and developments

This section details ongoing planning, developments, and discussions regarding support for offshore wind in NSEC countries and the UK. These countries are either in the process of adapting a previous support scheme (e.g. moving from negotiated tenders to auctions, changing tender rules) or have yet to implement a dedicated support policy for offshore wind. This section includes developments up until early July 2020.

2.1.3.1 Belgium

In April 2019, the federal parliament of Belgium[46] adopted a law introducing an auction-based support scheme to award concessions for offshore wind sites; the second phase of offshore wind development in Belgium. This change should speed up the administrative application and award procedure, increase renewable energy production by 2030, reduce societal cost of support for offshore wind, and align with the Commission's State Aid Guidelines.[47] The law aims to establish general principles for the competitive bidding procedure of future offshore renewable energy projects. The new projects will be located in a new 281 km² zone in the North Sea, close to the French border (with specific sites still to be defined). The new zone will accommodate at least 1.7 GW, bringing total offshore wind capacity to 4 GW by 2030.[48] Larger offshore wind farm sites are being envisioned in this zone, with expected minimum concession sizes of 700 MW. The objective is to organise the tender by 2022-2023 with new installations operational by 2025. A key boundary condition to the plans is the timely realisation of required grid developments both offshore and onshore.

The site selection and pre-investigation during the second phase is planned to be performed by the government rather than developers and site information, such as pre-investigation studies, will be shared with prospective bidders. The successful bidder in the auction will receive all required permits and licences to develop, build, and operate the wind farm.[49] According to the adopted law, concessions could be awarded for a maximum of 30 years and any support payment is limited to a 15-year-period.[50] The law gives the government the possibility of requiring a financial guarantee (e.g. a bank guarantee) to ensure the timely construction and operation of the installations. Candidates will have to meet minimum eligibility criteria. The Belgian TSO Elia is to build and operate transmissions assets, up to and including the offshore substations.

Figure 2-4 presents the current offshore wind farms with domain concessions granted during the first offshore wind phase and the planned new offshore renewable energy zones in the North Sea

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[46] Allen & Overy, 2019. Belgium adopts legal framework on tenders for new offshore electricity production installations. https://www.allenovery.com/en-gb/global/news-and-insights/publications/belgium-adopts-legal-framework-on-tenders-for-new-offshore-electricity-production-installations; EC, 2018. State aid: Commission approves €3.5 billion support to three offshore wind farms in Belgium. https://ec.europa.eu/commission/presscorner/detail/en/IP_18_5922; WindEurope, 2019. Wind energy in Europe: National policy and regulatory developments. http://svenskvindenergi.org/wp-content/uploads/2019/03/Wind-Energy-in-Europe-National-Policy-and-Regulatory-Developments-January2019-WindEurope-For-MEMBERS-ONLY.pdf

[47] Chamber of Representatives of Belgium (Kamer van volksvertegenwoordigers), 2019. Bill DOC 54 3581/001. https://www.dekamer.be/FLWB/PDF/54/3581/54K3581001.pdf

[48] Federal Government of Belgium, 2019. Belgian offshore wind energy – 4 GW by 2030. https://economie.fgov.be/nl/themas/energie/energiebronnen/hernieuwbare-energieen/hernieuwbare-energiebronnen-de/belgische-offshore-windenergie

[49] See Footnote 48

[50] Allen & Overy, 2019. Belgium adopts legal framework on tenders for new offshore electricity production installations. https://www.allenovery.com/en-gb/global/news-and-insights/publications/belgium-adopts-legal-framework-on-tenders-for-new-offshore-electricity-production-installations

following the Marine Spatial plan.[51] Current plans are to establish a site-specific, technology-neutral system for offshore-based installations, i.e. offshore wind energy and other sources of offshore renewable energy such as tidal, solar, and storage.

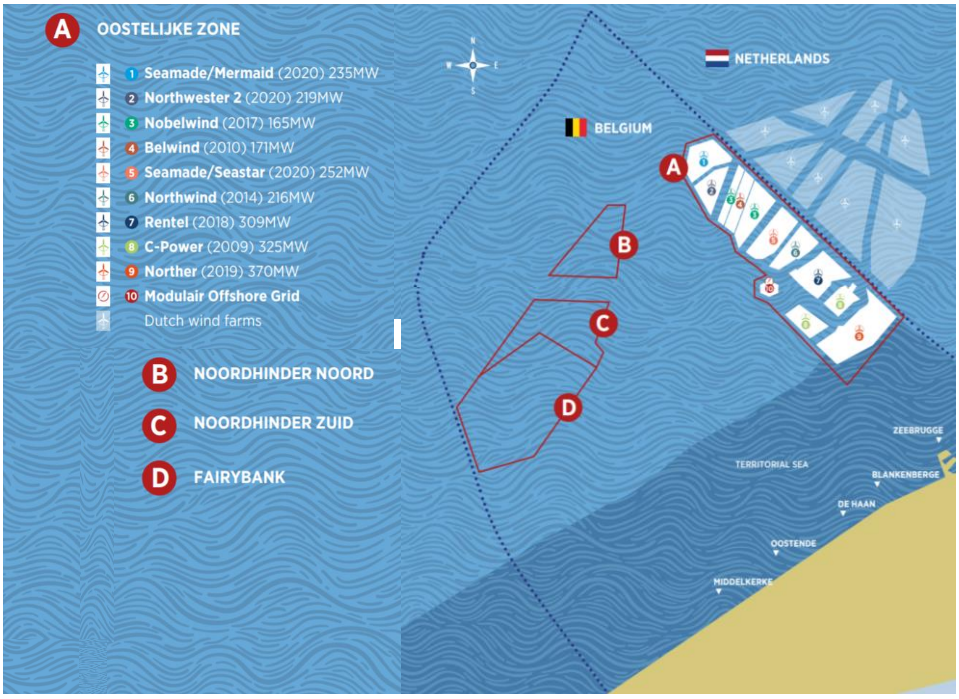

Figure 2-4. Belgian offshore wind farms and planned new zones for the second phase. *(Source: adapted from BOP, 2019)*[52]

The exact tender design for offshore wind sites is to be decided by the federal government and is subject to recommendation from the federal regulator (CREG). The three options include:[53]

- Tenders competitively allocating subsidies or, if no subsidies are required, zero bid-tenders based on qualitative criteria like in the Netherlands.
- Tenders based on a fixed target price providing a sliding premium.
- Tenders allowing negative bids, that is, a concession model.

To establish the complete regulatory framework for this support scheme, the Belgian government needs to adopt a Royal Decree to implement key aspects and design features of the law. In addition, EC State Aid approval may become necessary. The proposed changes are more in line with the current Dutch award process and regulatory framework for offshore wind compared to the negotiation process used for the first offshore wind phase in Belgium.

[51] Federal Government of Belgium, n.d.. Royal Decree establishing the marine spatial planning for the period 2020 to 2026. https://www.health.belgium.be/sites/default/files/uploads/fields/fpshealth_theme_file/mspandsummarizedannexes.pdf

[52] Belgian Offshore Platform, 2019. Memorandum: Offshore wind energy in the Belgian part of the North Sea. https://www.belgianoffshoreplatform.be/app/uploads/BOP_memorandum_2019_A4_EN_GVD.pdf

[53] Allen & Overy, 2019. Belgium adopts legal framework on tenders for new offshore electricity production installations. https://www.allenovery.com/en-gb/global/news-and-insights/publications/belgium-adopts-legal-framework-on-tenders-for-new-offshore-electricity-production-installations

2.1.3.2 Denmark

Denmark has two different procedures for offshore wind development: an open-door procedure where developers propose sites and do site pre-development, and a tender procedure run by the Danish Energy Agency for specific sites.[54]

In the 2018 Energy Agreement,[55] Denmark committed to an offshore wind auction of approximately 800 MW (i.e. the Thor offshore wind farm tender) to be commissioned between 2024 and 2027, as well as two additional offshore wind tenders of at least 800 MW to be organised in 2021 and 2023, resulting in a minimum of 2,400 MW additional offshore capacity by 2030. For the Thor tender, the grid connection costs and the responsibility for grid connection moves to the developer and the support scheme adopted is a capped CfD.[56] In May 2020, the developer European Energy received the approval of the environmental impact assessments (EIA) for its Omø South and Jammerland Bay OWP through the open-door process it started in 2012.[57] This would result in a total capacity of 560 MW with expected commissioning in 2023.

Denmark has great interest in hybrid and international projects, as demonstrated by two ongoing developments: Kriegers flak and the recently announced two energy islands. The Danish Kriegers Flak wind farm (commissioned in late 2020[58]) will have a connection with Danish onshore grid and the German Baltic 2 wind farm (see Figure 2-5).[59]

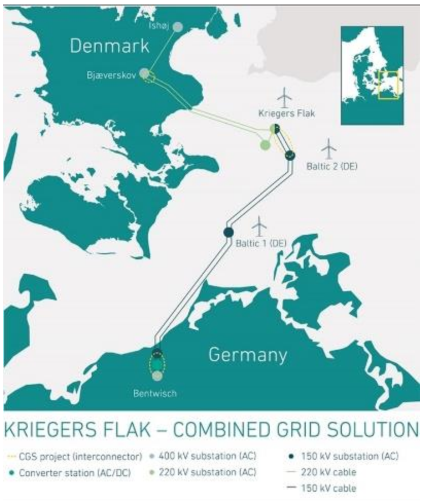

Figure 2-5. Kriegers Flak Combined Grid Solution. *(Source: Energinet, 2019)*[60]

[54] Danish Energy Agency, 2020. Procedures and Permits for Offshore Wind Parks. https://ens.dk/en/our-responsibilities/wind-power/offshore-procedures-permits

[55] WindEurope, 2019. Wind energy in Europe: National policy and regulatory developments. http://svenskvindenergi.org/wp-content/uploads/2019/03/Wind-Energy-in-Europe-National-Policy-and-Regulatory-Developments-January2019-WindEurope-For-MEMBERS-ONLY.pdf; , Hogan Lovells, 2019. Offshore Wind Worldwide Regulatory Framework in Selected Countries. https://www.hoganlovells.com/~/media/germany_folder-for-german-team/artikel/2020_offshorewindworldwide.pdf?la=en

[56] OffshoreWindBiz, 2019. Denmark Rolls Out New Subsidy Scheme for Offshore Wind. https://www.offshorewind.biz/2019/11/15/denmark-rolls-out-new-subsidy-scheme-for-offshore-wind/

[57] OffshoreWindBiz, 202. European Energy Gets OK for Danish Offshore Wind Pair. https://www.offshorewind.biz/2020/05/26/european-energy-gets-ok-for-danish-offshore-wind-pair/

[58] OffshoreWindBiz, 2020. Kriegers Flak CGS Launch Delayed Again. https://www.offshorewind.biz/2020/07/03/kriegers-flak-cgs-launch-delayed-again/

[59] Vattenfall, 2019. News: construction of Kriegers Flak Offshore Wind Farm has started. https://group.vattenfall.com/press-and-media/news--press-releases/newsroom/2019/construction-of-kriegers-flak-offshore-wind-farm-has-started; Energinet.dk, 2019. Kriegers Flak – Combined Grid Solution. https://en.energinet.dk/Infrastructure-Projects/Projektliste/KriegersFlakCGS

[60] Energinet, 2019. Kriegers Flak – Combined Grid Solution. https://en.energinet.dk/Infrastructure-Projects/Projektliste/KriegersFlakCGS

On 20 May 2020, the Danish Ministry of Finance announced its six-pillar climate action plan with a key role for offshore wind development connected to energy islands.[61] Two energy islands are foreseen, with each connecting minimum 2 GW of offshore wind (**Figure 2-6**):

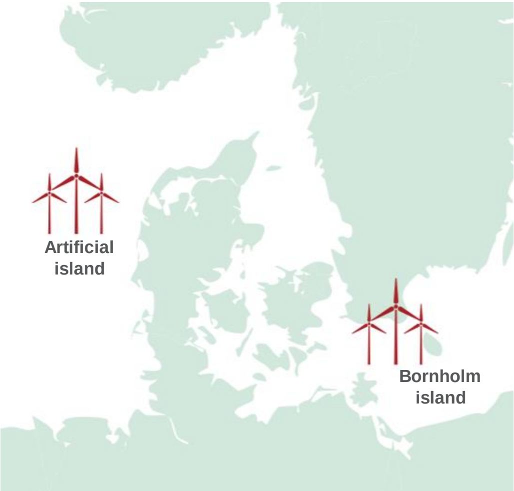

Figure 2-6. Schematic locations of the two proposed energy islands. *(Source: Adapted from Danish Government, 2020)*[62]

- An artificial island in the North Sea with connections to Denmark and the Netherlands by 2030 which could connect 10 GW of offshore wind in the long run.

- A conversion of the Bornholm island in the Baltic Sea with connections to Denmark and Poland to connect up to 2 GW by 2030.

Mid-2020, the Danish government signed a climate agreement[63] including an agreement to develop two islands by 2030 following the climate action plan, and the establishment of the second of the three tenders (Hesselø 800-1,000 MW with the option to overplant up to 200 MW) with planned commissioning in 2027.[64]

In April 2019, the Danish government identified locations for 12.4 GW future offshore wind energy for developments beyond 2030. The government also estimates that the country has a potential to add a total of 40 GW offshore wind capacity.[65] In June 2020, the Danish Energy Agency mapped out areas in the North Sea and the Baltic Sea suitable for the development of up to 18 GW of offshore wind

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[61] Danish Government, 2020. Regeringen vil bygge verdens to første energiøer med ny klimaplan. https://www.regeringen.dk/nyheder/2020/regeringen-vil-bygge-verdens-to-foerste-energioeer-med-ny-klimaplan/; Danish Government, 2020. Markante drivhusgasreduktioner og investeringer i den grønne omstilling. https://fm.dk/media/18017/faktaark-til-foerste-del-af-klimahandlingsplanen.pdf

[62] Danish Government, 2020. Markante drivhusgasreduktioner og investeringer i den grønne omstilling. https://fm.dk/media/18017/faktaark-til-foerste-del-af-klimahandlingsplanen.pdf

[63] Danish Government, 2020. Broad climate agreement brings Denmark back on track (Bred klimaaftale bringer Danmark tilbage i den grønne førertrøje). https://www.regeringen.dk/nyheder/2020/bred-klimaaftale-bringer-danmark-tilbage-i-den-groenne-foerertroeje/; OffshoreWindBiz, 2020. Denmark Greenlights 5 GW Energy Islands, Second 1 GW Offshore Wind Farm. https://www.offshorewind.biz/2020/06/22/denmark-greenlights-5-gw-energy-islands-second-1-gw-offshore-wind-farm/; Danish Government, 2020. Bred klimaaftale bringer Danmark tilbage i den grønne førertrøje. https://www.regeringen.dk/nyheder/2020/bred-klimaaftale-bringer-danmark-tilbage-i-den-groenne-foerertroeje/

[64] OffshoreWindBiz, 2020. Denmark Speeds Up Hesselø Tender, Adds Overplanting Option. https://www.offshorewind.biz/2020/07/02/denmark-speeds-up-hesselo-tender-adds-overplanting-option/

[65] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe. Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. Available online: https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

capacity for standalone wind farms and several continuous wind farms that could be connected to the planned energy islands.[66]

2.1.3.3 France

France has had a competitive tender in place since the third offshore wind round (Dunkirk).[67] In 2019, the French multi-annual energy plan PPE (Plan de Programmation Pluriannuelle de l'Energie)[68] was released. On 21 April 2020, the French Ministry of the ecological and solidary transition adopted the PPE by a decree, announcing a provisional planning for offshore wind call for tenders under a similar tender design as the third round, see
Table 2-2. The government will select and pre-develop the sites for fixed bottom and floating wind. Following a change of law in 2018, the TSO now also finances the connections, which was previously allocated to the developers.[69] The planned sites are envisioned to be on average between 700 MW and 1 GW. The PPE will be updated to reflect recent evolutions in market prices and costs as the current Dunkirk tender price is already below the provisional target prices (i.e. capped tender prices) determined by the French Government of the upcoming tenders.[70]

Table 2-2. Provisional timeline of offshore wind allocations and target prices. *(Source: French Government, 2020)*[71]

<table>
<tr><th></th><th>Floating capacity (750 MW)</th><th>Fixed- bottom capacity (2.5 GW-3 GW)</th></tr>
<tr><td>2019</td><td></td><td>600 MW Dunkirk (€45/MWh)</td></tr>
<tr><td>2020</td><td></td><td>1000 MW Manche Est Mer du Nord (€60/MWh)</td></tr>
<tr><td>2021</td><td>250 MW Bretagne Sud (120 EUR/MWh)</td><td rowspan="2">500 MW-1,000 MW Sud-Atlantique (€60/MWh)</td></tr>
<tr><td>2022</td><td>2 x 250 MW Mediterranean (110 EUR/MWh)</td></tr>
<tr><td>2023</td><td></td><td>1,000 MW (€50/MWh)</td></tr>
<tr><td>>2024</td><td colspan="2">1,000 MW per year fixed or floating depending on prices and type of installation with target rates reducing towards the market price at the time of build</td></tr>
</table>

[66] Danish Energy Agency, 2020. The Danish Energy Agency publishes granular mapping of areas for possible offshore wind farms (Energistyrelsen offentliggør finscreening af arealer til mulige havvindmølleparker). https://presse.ens.dk/news/energistyrelsen-offentliggoer-finscreening-af-arealer-til-mulige-havvindmoelleparker-403920 ; OffshoreWind.biz, 2020. Denmark Rolls Out 18 GW Offshore Wind Map. https://www.offshorewind.biz/2020/06/05/denmark-rolls-out-18-gw-offshore-wind-map/

[67] EC, 2018. Aide d'État SA.51061 (2018/N) – France Parc éolien en mer dans une zone au large de Dunkerque. https://ec.europa.eu/competition/state_aid/cases1/201927/274555_2079310_198_2.pdf

[68] French Government, 2020. French Energy and Climate Strategy (Stratégie française pour l'énergie et le climat – programmation pluriannuelle de l'energie (2019-2023, 2024-2028)). https://www.ecologique-solidaire.gouv.fr/sites/default/files/20200422%20Programmation%20pluriannuelle%20de%20l%27e%CC%81nergie.pdf

[69] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. Available online: https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

[70] Hogan Lovells, 2019. Offshore Wind Worldwide Regulatory Framework in Selected Countries. https://www.hoganlovells.com/~/media/germany_folder-for-german team/artikel/2020_offshorewindworldwide.pdf?la=en

[71] French Government, 2020. Decree of 21 April 2020 on multi-annual energy plan. NOR:TRER2006667D (Décret du 21 avril 2020 relatif à la programmation pluriannuelle de l'énergie. NOR: TRER2006667D). https://www.ecologique-solidaire.gouv.fr/sites/default/files/TRER2006667D%20signe%CC%81%20PM.pdf

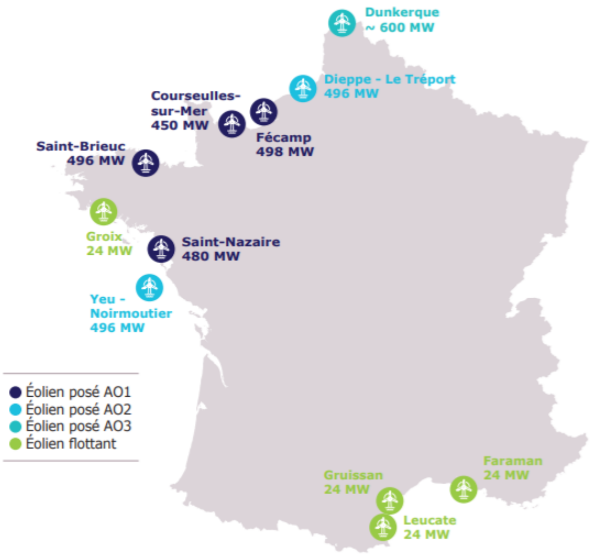

Figure 2-7. Currently allocated wind farm connections. *(Source: RTE, 2019)*[72]

2.1.3.4 Germany

The German Renewable Energy Sources Act (EEG 2017) sets an offshore wind target of 6.5 GW by 2020 and 15 GW by 2030.[73] In May 2020, the federal government agreed with the coastal states (Küstenländer) and the TSOs to rise the 2030 target to 20 GW, provided that the additionally necessary grid connections will be built on time.[74] On 3 June, the cabinet adopted the 20 GW target and added the ambition of a 40 GW target in 2040.[75]

The Offshore Wind Energy Act (WindSeeG) sets the framework for the auction, both for the transitional scheme in place between 2017 and 2018 and the auction rounds starting from 2021 onwards (the so-called central scheme). Central auction rounds are scheduled between 2021 and 2026 with annual auction values between 500 MW and 900 MW. The Federal Maritime and Hydrographic Agency (BSH) pre-develops the sites, which have been determined in the Site Development Plan (Flächenentwicklungsplan).[76] 3.9 GW will be in the North Sea and the remaining 300 MW in the Baltic Sea. Figure 2-8 details the new offshore wind energy in zones Germany. How the auction volume will be adapted to reflect the rising targets was not decided at the time of writing this report.

[72] Energy Regulatory Commission (Commission de Régulation de l'Énergie), 2020. French Transmission network development plan (Le schéma décennal de développement du reseau). https://assets.rte france.com/prod/public/2020-07/SDDR%202019%20Chapitre%2006%20-%20Le%20r%C3%A9seau%20en%20mer.pdf

[73] Federal Ministry of Economics and Technology (Germany), 2017. Renewable Energy Sources Act (EEG 2017). https://www.bmwi.de/Redaktion/EN/Downloads/renewable-energy-sources-act-2017.pdf%3F__blob%3DpublicationFile%26v%3D3; Hogan Lovells, 2020. Offshore Wind Worldwide. Regulatory Framework in Selected Countries. https://www.hoganlovells.com/~/media/germany_folder-for-german-team/artikel/2020_offshorewindworldwide.pdf?la=en

[74] Federal Ministry of Economics and Technology (Germany), 2020. 20GW Offshore Wind Energy by 2030 (Mehr Strom vom Meer. 20 Gigawatt Offshore-Windenergie bis 2030 realisieren). https://www.bmwi.de/Redaktion/DE/Downloads/M-O/offshore-vereinbarung-mehr-strom-vom-meer.pdf?__blob=publicationFile&v=6

[75] Federal Ministry of Economics and Technology (Germany), 2020. Rückenwind für den Klimaschutz. https://www.bundesregierung.de/breg-de/bundesregierung/bundeskanzleramt/windenergie-auf-see-1757176

[76] Federal Ministry of Economics and Technology (Germany), 2017. Offshore Wind Energy Act (WindSeeG 2017). https://www.bmwi.de/Redaktion/DE/Downloads/E/windseeg-gesetz-en.pdf?__blob=publicationFile&v=9

In 2017, Germany was the first country to receive zero-bid offers for the Borkum Riffgrund West 2 wind farm, the He Dreiht wind farm, and the OWP West wind farm, which all have an expected commissioning for 2024-2025.[77] Zero prices are only possible under the specific circumstances related to the site (e.g. North Sea versus more challenging Baltic Sea conditions) and the expectations of the bidders regarding technology and power price developments over the lifetime of the projects. In addition, the offshore wind transmission assets mostly fall under the responsibility of the TSO, reducing developer's scope (see section 2.2). Due to the zero bids, changes to the support scheme are required:

- The lowest bid of the transitory scheme currently sets the ceiling price for the central scheme, which is consequently zero and would not allow for positive bids.

- If more than one bidder is willing to realise a site without support, no selection is possible.

The draft of the Offshore Wind Energy Act of June 2020 foresees the following changes to address the issues. First, the ceiling price rises to 7.3 €cents/kWh in 2021, 6.4 €cents/kWh in 2022 and 6.2 €cent/kWh in 2023. Second, the government proposes to introduce the possibility for a concessional payment from the project developer to the TSO in case more than one bidder is willing to realise the site without a subsidy.[78] A new dynamic tendering process is proposed allowing competing bidders to see willingness to pay from other bidders, to ensure the successful bid is not higher than necessary.[79] Many stakeholders heavily criticise the introduction of the option for a concessional payment (e.g. the BWO,[80] the BDEW,[81] the VKU[82]). It remains to be seen whether the German Parliament will finally adopt the changes proposed by the Government in June 2020.[83]

[77] Clean Energy Wire, 2020. German offshore wind power - output, business and perspectives. https://www.cleanenergywire.org/factsheets/german-offshore-wind-power-output-business-and-perspectives

[78] Federal Ministry of Economics and Technology (Germany), 2020. Draft Law amending the Offshore Wind Energy Law and other Regulations (Gesetzentwurf der Bundesregierung - Entwurf eines Gesetzes zur Änderung des Windenergie-auf-SeeGesetzes und anderer Vorschriften). https://www.bmwi.de/Redaktion/DE/Downloads/E/entwurf-eines-gesetzes-zur-aenderung-des-windenergie-auf-see-gesetzes.pdf?__blob=publicationFile&v=6

[79] OffshoreWind.biz, 2020. Germany Drafts Offshore Wind Bill with 40 GW-by-2040 Goal, Dynamic Tendering Process. https://www.offshorewind.biz/2020/06/01/germany-drafts-offshore-wind-bill-with-40-gw-by-2040-goal-dynamic-tendering-process/

[80] Federal Association of Offshore Windfarm Operators (BWO), 2020. Offshore Wind Draft Law an Obstacle for reaching Offshore Wind Capacity Targets^^ (Entwurf des WindSeeG erschwert Erreichen der Ausbauziele). https://www.bwo-offshorewind.de/entwurf-des-windseeg-erschwert-erreichen-der-ausbauziele/

[81] German Association of Energy and Water Industries (BDEW), 2020. BDEW supports higher targets for offshore wind capacity (BDEW zur Anhebung der Ausbauziele für Windenergie auf See). https://www.bdew.de/presse/presseinformationen/bdew-zur-anhebung-der-ausbauziele-fuer-windenergie-auf-see/

[82] German Association of Local Public Utilities (VKU), 2020. VKU to support Amendment of Offshore Wind Law (VKU zur Änderung des Windenergie-auf-See-Gesetzes). https://www.vku.de/presse/pressemitteilungen/archiv-2020-pressemitteilungen/vku-zur-aenderung-des-windenergie-auf-see-gesetzes/

[83] OffshoreWindBiz, 2020. German Federal Council Calls for 30 GW of Offshore Wind by 2035, Rapid EEG Reform. https://www.offshorewind.biz/2020/07/06/german-federal-council-calls-for-30-gw-of-offshore-wind-by-2035-rapid-eeg-reform/; OffshoreWindBiz, 2020. Germany: Federal Council Recommends Against Proposed Offshore Wind Tendering Model. https://www.offshorewind.biz/2020/07/06/germany-federal-council-recommends-against-proposed-offshore-wind-tendering-model/

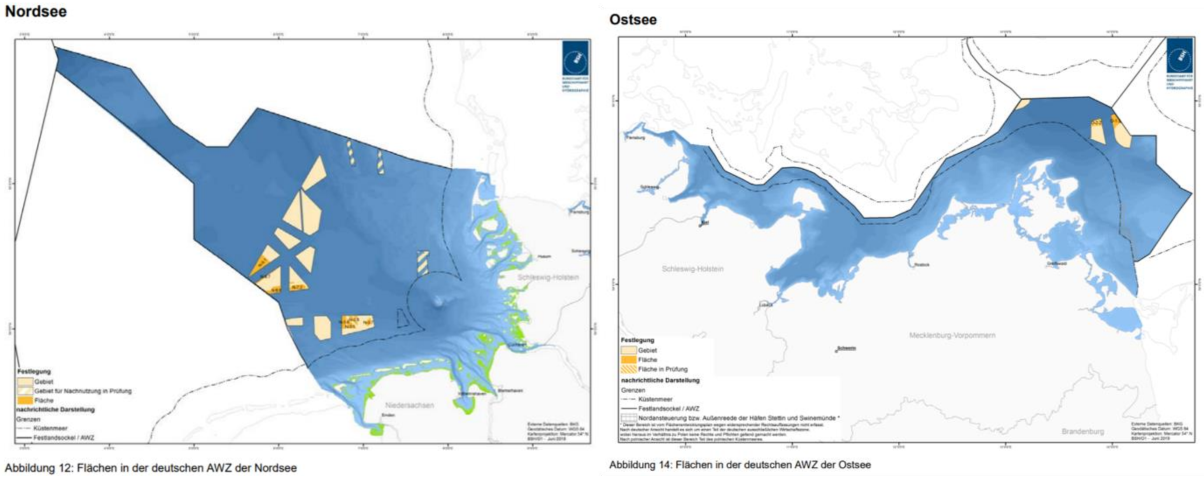

Figure 2-8. Overview map of offshore wind energy zones in the North and East sea in Germany. *(Source: BSH, 2019)[84]*

One of the operational wind farms is the German Baltic 2 wind farm, which will connect with German onshore grid and the Danish Kriegers Flak wind farm (see Figure 2-5 and section 2.1.3.2), making the wind farm part of a hybrid project.[85]

2.1.3.5 Ireland

Ireland's target to develop 3.5 GW of offshore wind by 2030 is in its Climate Action Plan (CAP).[86] Currently only one small wind farm is operational in Ireland (Arklow Bank wind farm of 25 MW, commissioned in 2004). Previous support schemes did not result in much uptake of offshore wind capacity but did create a large pipeline of offshore wind projects. A renewable energy support scheme (RESS) is under development, envisioned to consist of five competitive auction rounds that will be scheduled frequently.[87] The final version of the first technology-neutral RESS round was published in February 2020.[88,89,90] The scheme is still subject to state aid approval but auctions are planned to be conducted from 2020 onwards. The RESS 1 auction round is foreseen to take place in 2020 with a maximum auction volume of 3,000 GWh with a CfD scheme. The qualification round for the RESS 1

[84] Federal Maritime and Hydrographic Agency of Germany, 2019. 2019 Land Development Plan for North Sea and Baltic Sea (Flächenentwicklungsplan 2019 für die deutsche Nord- und Ostsee). https://www.bsh.de/DE/PUBLIKATIONEN/_Anlagen/Downloads/Offshore/FEP/Flaechenentwicklungsplan_2019.pdf?__blob=publicationFile&v=8

[85] Vattenfall, 2019. News: Construction of Kriegers Flak Offshore Wind Farm has started. https://group.vattenfall.com/press-and-media/news--press-releases/newsroom/2019/construction-of-kriegers-flak-offshore-wind-farm-has-started; Energinet, 2019. Kriegers Flak – Combined Grid Solution. https://en.energinet.dk/Infrastructure-Projects/Projektliste/KriegersFlakCGS

[86] Government of Ireland, 2019. Climate Action Plan 2019. https://www.dccae.gov.ie/documents/Climate%20Action%20Plan%202019.pdf

[87] Department of Communications, Climate Action & Envronment (Ireland), 2019. Renewable Electricity Support Scheme (RESS) High Level Design. https://www.dccae.gov.ie/documents/RESS%20Design%20Paper.pdf

[88] Department of Communications, Climate Action & Environment (Ireland), 2020. Renewable Electricity Support Scheme (RESS). https://www.dccae.gov.ie/en-ie/energy/topics/Renewable-Energy/electricity/renewable-electricity-supports/ress/Pages/default.aspx

[89] Department of Communications, Climate Action & Environment (Ireland), 2019. Minister Bruton announces scheme to reach 70% renewables. https://www.dccae.gov.ie/en-ie/news-and-media/press-releases/Pages/Minister-Bruton-Announces-Scheme-to-Reach-70-Renewables.aspx; DCCAE, 2019. Public Consultation on the Draft RESS Terms and Conditions. https://www.dccae.gov.ie/en-ie/energy/consultations/Pages/Public-Consultation-on-the-Draft-RESS-Terms-and-Conditions.aspx

[90] Government of Ireland, 2019. Terms and Conditions of the First Competition under the Renewable Electricity Support Scheme, RESS 1: 2020. https://www.dccae.gov.ie/en-ie/energy/consultations/Pages/Public-Consultation-on-the-Draft-RESS-Terms-and-Conditions.aspx

auction opened on 9 March 2020.[91]Offshore wind would compete with other technologies in the first round. Future RESS rounds are expected to offer offshore wind specific support, as outlined in the CAP. Offshore wind farms are unlikely to participate in the first auction round, as there is still a lack of clarity around offshore licencing and grid connection arrangements that would make developing those assets challenging in the timeframe. The Irish government targets the second and third auction rounds for offshore wind deployment.[92]

Under the previous support schemes and the current RESS 1, developers are responsible for site selection, pre-development, and all required permits and leases. Next to the support scheme reform for offshore wind, an update in marine spatial planning is being conducted in line with the European Marine Spatial Planning Directive (Directive 2014/89/EU): the National Marine Planning Framework (NMPF)[93] and the Marine Planning and Development Management (MPDM) Bill.[94] Both will impact the marine spatial planning and consenting processes for offshore renewables.

Despite the high offshore wind potential, previous support schemes have not resulted in much offshore wind development in Ireland due to complex permitting and grid connection processes.[95] However, a large number of projects (~10 GW) are in the pipeline, many of which are still in an early stage of development.[96] Approximately 5.6 GW of this capacity has applied for a grid connection (i.e. an onshore connect point).[97] Some projects have developed further by obtaining a site lease Foreshore Act 1933 or grid connection offer from the Irish TSO EirGrid.

To ensure offshore wind development continues during the changes in the marine and support framework, the Irish government has defined criteria to qualify some of the projects in the pipeline as Relevant Projects, which can continue their development under a transitional protocol.[98] On 19 May 2020, the Irish Department of Communications, Climate Action and Environment announced seven offshore wind farms, in total up to 3.9 GW, that are nominated as Relevant Project and will be fast tracked.[99] These relevant projects can apply for final consent under the new regime to provide further public consultation. The developments approved include two projects by Innogy Renewables, two projects by Codling Wind Farm, Oriel Wind Farm, Fuinneamh Sceirde Teoranta, and North Irish Sea

[91] Department of Communications, Climate Action & Environment, 2020. Renewable Electricity Support Scheme (RESS). https://www.dccae.gov.ie/en-ie/energy/topics/Renewable-Energy/electricity/renewable-electricity-supports/ress/Pages/default.aspx

[92] Riviera Maritime Media, 2019. First Irish auction probably too early for offshore wind. https://www.rivieramm.com/news-content-hub/news-content-hub/first-irish-auction-comes-too-early-for-offshore-wind-57026

[93] Department of Housing, Planning and Local Government (Ireland), 2019. Draft National Marine Planning Framework. https://www.housing.gov.ie/planning/marine-planning/public-consultation-draft-national-marine-planning-framework

[94] Department of Housing, Planning and Local Government (Ireland), 2019. The Marine Planning and Development Management Bill. https://www.housing.gov.ie/planning/marine-spatial-planning/foreshore/marine-planning-and-development-management-bill

[95] Irish Examiner, 2019. Ireland emerging as attractive market for offshore wind. https://www.irishexaminer.com/breakingnews/ireland/ireland-emerging-as-attractive-market-for-offshore-wind-929987.html A joint Cornwall Insight Ireland, ORE Catapult and Pinsent Masons, 2018. A great leap forwards? Offshore wind in Ireland. http://alerts.pinsentmasons.com/rs/emsimages/pdf/Great-leap-forward-Offshore-wind-in-Ireland.pdf

[96] Irish Wind Energy Association (IWEA), 2019. New Horizons: Ireland's Offshore Wind https://www.iwea.com/images/Article_files/1._9.15_David_Connolly_IWEA_Offshore_Conference_12_Sept.pdf

[97] EirGrid, Offshore Wind-substation and Cable Functional Specification Revisions, 2019. http://www.eirgridgroup.com/customer-and-industry/becoming-a-customer/generator-connections/offshore-wind-substation/

[98] Department of Housing, Planning and Local Government (Ireland), 2019. The Marine Planning and Development Management Bill. https://www.housing.gov.ie/planning/marine-spatial-planning/foreshore/marine-planning-and-development-management-bill

[99] Department of Communications, Climate Action & Environment (Ireland), 2020. Ministers English and Bruton Announce the Transition of Offshore Renewable Energy Projects. https://www.dccae.gov.ie/en-ie/news-and-media/press-releases/Pages/Ministers-English-and-Bruton-Announce-the-Transition-of-Offshore-Renewable-Energy-Projects.aspx

Array Ltd (Figure 2-9 and Table 2-3). Relevant projects can participate in the RESS Tenders with a maximum price of €120/MWh for the technology neutral RESS1 round under a CfD scheme.[100]

Table 2-3. List of Relevant fixed-bottom offshore wind projects in Ireland with expected capacities. *Source: 4COffshore, 2020[101], IWEA, 2019[102]*

Wind farm	Location	Capacity	Developer
Oriel Wind Farm	Louth	330 MW	Oriel, Parkwind, ESB
Two projects Bray and Kish Banks – Dublin Array	Dublin	600 MW	Innogy, Saorgus Energy
Codling Wind Farm, (two projects, Codling I and Codling II)	Wicklow	1,100 MW (I) 1,000 MW (II)	Fred Olsen, Hazel Shore
Fuinneamh Sceirde Teoranta, (Skerd Rocks)	Galway	400	Fuinneamh Sceirde Teoranta
North Irish Sea Array Ltd, (North Irish Sea Array)	Louth/Meath	530 MW	Statkraft

Figure 2-9. Graphical representation of location of Relevant Projects. *(Source: Guidehouse based on 4COffshore, 2020)[103]*

In June 2020, the new government coalition formulated a draft government plan.[104] This draft plan includes the development of a plan to achieve 5 GW of offshore wind by 2030 on Ireland's southern and eastern coasts, up from the current 3.5 GW target. In addition, it announces the intention to develop floating offshore wind potential and to hold an offshore-specific RESS auction in 2021.

2.1.3.6 Luxembourg

Luxembourg is landlocked and therefore does not have any offshore wind projects or support schemes in place. However, it is part of the NSEC countries for the collaboration on offshore

[100] Government of Ireland, 2020. Terms and Conditions for the first competition under the Renewable Electricity Support Scheme – RESS 1: 2020. https://www.dccae.gov.ie/documents/RESS_1_Terms_and_Conditions.pdf
[101] 4COffshore, 2020. Offshore Wind farms in Ireland. https://www.4coffshore.com/windfarms/ireland/
[102] Irish Wind Energy Association (IWEA), 2019. New Horizons: Ireland's Offshore Wind https://www.iwea.com/images/Article_files/1._9.15_David_Connolly_IWEA_Offshore_Conference_12_Sept.pdf
[103] 4COffshore, 2020. Offshore Wind farms in Ireland. https://www.4coffshore.com/windfarms/ireland/
[104] Government of Ireland, 2020. Our shared future. https://static.rasset.ie/documents/news/2020/06/draft-programme-for-govt.pdf

renewable developments in the North Sea. In November 2019, Luxembourg's energy minister Claude Turmes urged for countries holding offshore wind tenders to open those up for cross-border cooperation with other landlocked European countries.[105] This demonstrates Luxembourg's ambition to play a role in future European offshore energy developments.

2.1.3.7 Netherlands

The Netherlands adopted a competitive tender for the award of offshore wind sites. From the Hollandse Kust (zuid) I and II tender, provisions were included for qualitative criteria to allow for zero-bids (tender without subsidy). This resulted in the first zero subsidy bids for this tender in 2017. In the Hollandse Kust (zuid) III and IV tender, all bids were zero-subsidy bids that were differentiated and scored based on qualitative criteria, including an effective risk mitigation strategy.[106] For the upcoming tenders, a revision of the law for offshore wind (Wet Windenergie op Zee[107]) from 2019 allows for another tender design option that would require the developers to bid to develop at a site (i.e. negative bids) or other qualitative criteria. The revision also includes the option for hydrogen production from offshore wind farms; suitability will be assessed on a site-by-site basis.[108] Site selection and pre-development will remain the responsibility of the Dutch Enterprise Agency (RVO) and grid development will remain the responsibility of the Dutch TSO TenneT (see section 2.2).

The low/zero bids in the Dutch market can be attributed to several factors that keep the cost to developers down and mitigate and reduce their risks:[109]

- The grid connection is the TSO's responsibility, shifting the risks and costs away from the developer (see section 2.2).
- The one-stop-shop principle of awarding offshore wind farm concession, permit, and grid connection during an auction provides certainty to developers, further reducing developer risks.
- The established power purchase agreement (PPA) market in the Netherlands, which allows developers to further manage their risks.
- The good offshore wind site conditions in the Netherlands of relatively shallow water depths and high wind resource availability.
- The large size of the wind farm sites and their relative closeness to shore.
- Benefits from cost reduction realised throughout the supply chain in the Netherlands.
- The long-term auction schedule outlook, which provides developers confidence and allows developers to develop economies-of-scale.[110]

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[105] Recharge, 2019. Offshore wind countries should open tenders for land-locked nations. https://www.rechargenews.com/wind/-offshore-wind-countries-should-open-tenders-for-land-locked-nations-/2-1-713720

[106] AURES2 Project, 2019. Auctions for the support of renewable energy in the Netherlands. http://aures2project.eu/wp-content/uploads/2019/12/AURES_II_case_study_Netherlands.pdf

[107] Government of the Netherlands, 2019. Amendments to the Offshore Wind Energy Act (Wijziging van de Wet windenergie op zee). https://www.rijksoverheid.nl/documenten/kamerstukken/2019/04/04/wijziging-van-de-wet-windenergie-op-zee-ondersteunen-opgave-windenergie-op-zee

[108] See Footnote 107

[109] Guidehouse, 2019. Dutch Offshore Wind Market Update 2019. https://guidehouse.com/-/media/www/site/downloads/energy/2019/navigant-dutch-offshore-wind-market-update-2019.pdf

[110] AURES2, 2019. Auctions for the support of renewable energy in the Netherlands. http://aures2project.eu/wp-content/uploads/2019/12/AURES_II_case_study_Netherlands.pdf

The Dutch Ministry of Economic Affairs announced on 26 May 2020 in a Kamerbrief that it intends to extend the permit duration of the future offshore wind farms from 30 to maximally 40 years.[111] This measure will make the business case of offshore wind farm more robust. To adopt this extension, a revision to the Wet Windenergie op Zee was planned to be adopted at the end of 2020. For currently awarded wind farms, the bill will include an option to extend the duration of the award by approximately 20 years.

A total of 49 TWh of offshore wind is required to meet current CO_2 reduction targets from the Dutch Climate Agreement, which translates in ~10.6 GW of total installed offshore wind capacity by 2030.[112] This capacity could be increased if additional demand from electrification of demand sectors materialises. Offshore wind auctions are scheduled until 2024 and planned or expected until 2025 (Table 2-4). The Dutch offshore wind energy roadmap (Routekaart wind op zee) 2030 outlines nine development zones, of which five have been tendered and are under various stages of development (Figure 2-10).[113] Development is progressing as planned.

Table 2-4. Offshore wind project overview in the Netherlands. *Source: RVO and EZK, 2019*[114]

Pre-construction		
Project	**Capacity (MW)**	**Year of commissioning**
Borssele I & II	752	2020
Borssele III & IV	731.5	2020
Borssele V (innovation site)	20	2020
Under development		
Project	**Capacity (MW)**	**Year of commissioning**
Hollandse Kust Zuid I & II	740	2022
Hollandse Kust Zuid III & IV	760	2022
Early development stages		
Project	**Capacity (MW)**	**Year of commissioning**
Hollandse Kust Noord V (tender closed)	700	2023
Hollandse Kust West VI	700	2024
Hollandse Kust West VII	700	2025
Ten noorden van de Waddeneilanden	700	2026
IJmuiden Ver I & II	2,000	2027-2028
IJmuiden Ver III & IV	2,000	2029-2030

[111] Government of the Netherlands, 2020. Letter to Parliament on Future growth of offshore wind (Kamerbrief Toekomstige groei wind op zee). https://www.rijksoverheid.nl/ministeries/ministerie-van-economische-zaken-en-klimaat/documenten/kamerstukken/2020/05/26/kamerbrief-toekomstige-groei-wind-op-zee

[112] Guidehouse, 2019. Dutch Offshore Wind Market Update 2019. https://guidehouse.com/-/media/www/site/downloads/energy/2019/navigant-dutch-offshore-wind-market-update-2019.pdf

[113] RVO, 2020. Offshore Wind Energy in the Netherlands – Newsletter. https://offshorewind.rvo.nl/file/download/55040531

[114] Netherlands Enterprise Agency and Ministry of Economic Affairs and Climate (letter to Parliament 5 april 2019)

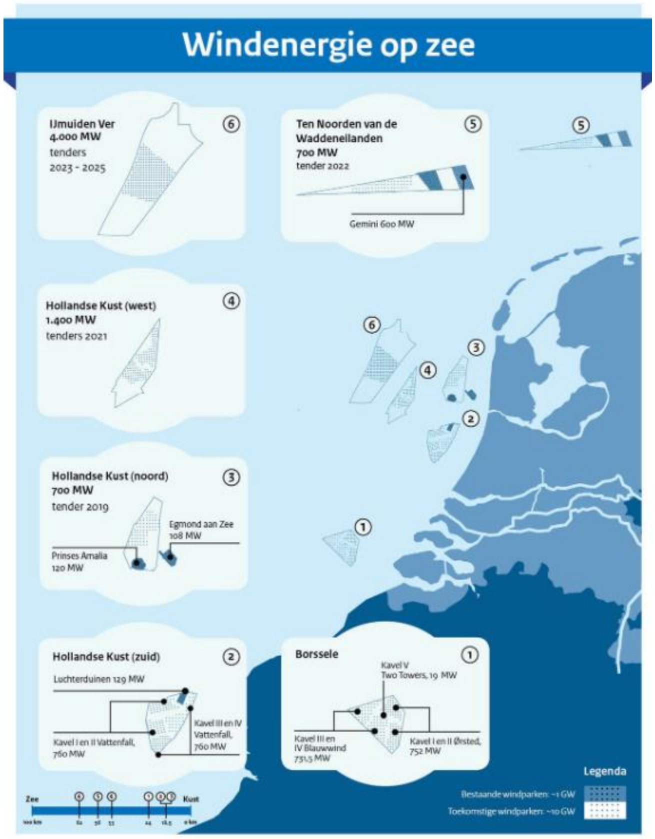

Figure 2-10. Dutch roadmap offshore wind 2030 "Routekaart wind op zee." *(Source: Rijksoverheid, 2020)*[115]

2.1.3.8 Norway

Norway's offshore wind potential is mainly governed by floating offshore wind due to its bathymetry. Norway currently has no offshore wind farms (apart from one small 2.3 MW site of the UNITECH Zefyros by Hywind Technology Offshore Wind Farm[116]) and no offshore wind support scheme in place. The Norwegian government plans to phase out the renewable energy green certificate system it operates jointly with Sweden since 2012, after 2021.[117] The government proposed a strategy for floating offshore wind in its 2018 state budget.[118]

In mid-2019, the Norwegian Ministry of Petroleum and Energy proposed opening sea areas for offshore wind,[119] with a subsequent public consultation on areas and regulation, which ran till

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[115] Government of the Netherlands, 2020. Offshore Wind Energy (Windenergie op zee). https://www.rijksoverheid.nl/onderwerpen/duurzame-energie/windenergie-op-zee

[116] 4COffshore, 2020. UNITECH Zefyros by Hywind Technology Offshore Wind Farm. https://www.4coffshore.com/windfarms/norway/unitech-zefyros-by-hywind-technology-norway-no04.html

[117] Wind Power Monthly, 2020. Sweden lines up 2021 subsidy stop. https://www.windpowermonthly.com/article/1663548/sweden-lines-2021-subsidy-stop

[118] Ministry of Petroleum and Energy (Norway), 2019. The Ministry of Petroleum and Energy proposes opening of area for offshore wind. https://www.regjeringen.no/en/aktuelt/the-ministry-of-petroleum-and-energy-proposes-opening-of-area-for-offshore-wind/id2655113/

[119] Ministry of Petroleum and Energy (Norway), 2019. The Ministry of Petroleum and Energy proposes opening of area for offshore wind. https://www.regjeringen.no/en/aktuelt/the-ministry-of-petroleum-and-energy-proposes-opening-of-area-for-offshore-wind/id2655113/

November 2019.[120] A proposed regulation of the ocean energy law, including more detailed rules about the license process, is also part of the consultation.[121] The proposed offshore wind areas are as follows (Figure 2-11):[122]

- Utsira Nord, with potential for 500-1,500 MW suitable for floating offshore wind and fairly close to shore (~25 km).

- Sandskallen – Sørøya Nord, with potential for 100 MW-300 MW, which has shallow and deeper waters suitable for floating and bottom-fixed offshore wind, fairly close to shore.

- And a consultation on whether to open the Sørlige Nordsjø II area (with potential for 1,000 MW-2,000 MW) close to the Danish border, which could allow connections with other European countries. In addition, this area also has ongoing petroleum activities that make it attractive for joint sector developments.

The proposed scheme for offshore wind includes zone selection by the government but site selection and pre-development by developers. The consultation document[123] states that not much competition is expected for licences for offshore wind development. The Ministry is evaluating how to introduce an aspect of competition into the licencing process. An administrative fee of NOK 100,000 could be part of licence applications. In terms of grid connection, the consultation document explicitly accommodates for direct connections to the onshore grid, connections to offshore petroleum platforms, or connections to other countries (hybrid projects).

In May 2020, several Norwegian ocean stakeholders asked the government in a letter to announce two full-scale floating offshore wind farms of at least 500 MW each with the aim of granting licenses during 2020.[124] On 12 June 2020, the Minister of Petroleum and Energy announced the opening of the Utsira Nord and Sørlige Nordsjø II areas for offshore renewables by Royal Decree allowing developers to submit license applications from 2021.[125]

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[120] Ministry of Petroleum and Energy (Norway), 2019. Offshore wind power: Public consultation on areas and regulation. https://www.regjeringen.no/en/aktuelt/offshore-wind-power-public-consultation-on-areas-and-regulation/id2662579/

[121] Ministry of Petroleum and Energy (Norway), 2019. Høyringsnotat. https://www.regjeringen.no/contentassets/942d48e60aee4fe6b0d6e1f51d75d2c3/hoyringsnotat-havenergi---opning-og-forskrift-l1060255.pdf

[122] Ministry of Petroleum and Energy (Norway), 2019. Offshore wind power: Public consultation on areas and regulation. https://www.regjeringen.no/en/aktuelt/offshore-wind-power-public-consultation-on-areas-and-regulation/id2662579/

[123] Ministry of Petroleum and Energy (Norway), 2019. Consultation Note (Høyringsnotat). https://www.regjeringen.no/contentassets/942d48e60aee4fe6b0d6e1f51d75d2c3/hoyringsnotat-havenergi---opning-og-forskrift-l1060255.pdf

[124] OffshoreWindBiz, 2020. Norwegians Call For Licensing of Two 500 MW Floating Wind Projects in 2020. https://www.offshorewind.biz/2020/05/04/norwegians-call-for-licensing-of-two-500-mw-floating-wind-projects-in-2020/

[125] Norwegian Government, 2020. Norway opens offshore areas for wind power. https://www.regjeringen.no/en/aktuelt/norway-opens-offshore-areas-for-wind-power/id2705986/

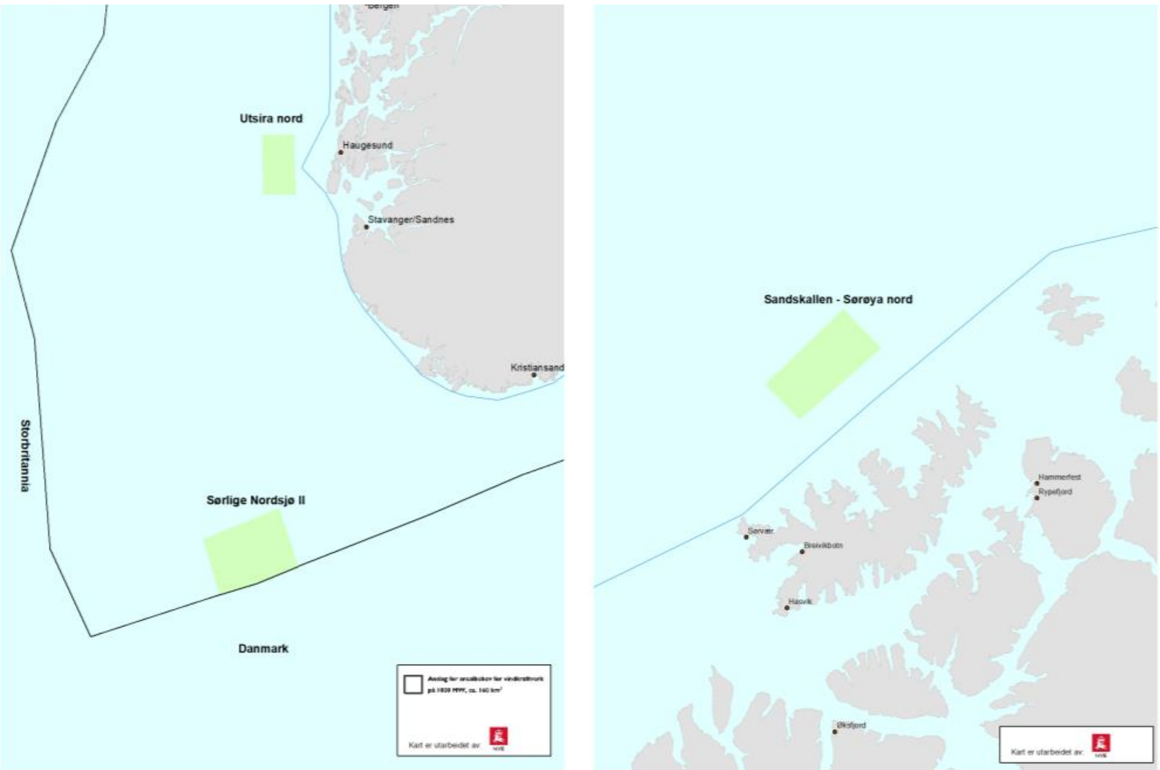

Figure 2-11. Proposed offshore wind zones in Norway. *(Source: Ministry of Petroleum and Energy, 2019)*[126]

Another recent offshore development is the plan for the first of its kind Hywind Tampen project (Figure 2-12), which will directly connect to the Snorre and Gullfaks oil & gas platforms.[127] The project was approved by the Norwegian Ministry of Petroleum and Industry in 2020 and will begin in Q3 2022.

[126] Ministry of Petroleum and Energy (Norway), 2019. Consultation Note (Høyringsnotat). https://www.regjeringen.no/contentassets/942d48e60aee4fe6b0d6e1f51d75d2c3/hoyringsnotat-havenergi---opning-og-forskrift-l1060255.pdf

[127] Equinor, 2020. Hywind Tampen: the world's first renewable power for offshore oil and gas. https://www.equinor.com/en/what-we-do/hywind-tampen.html

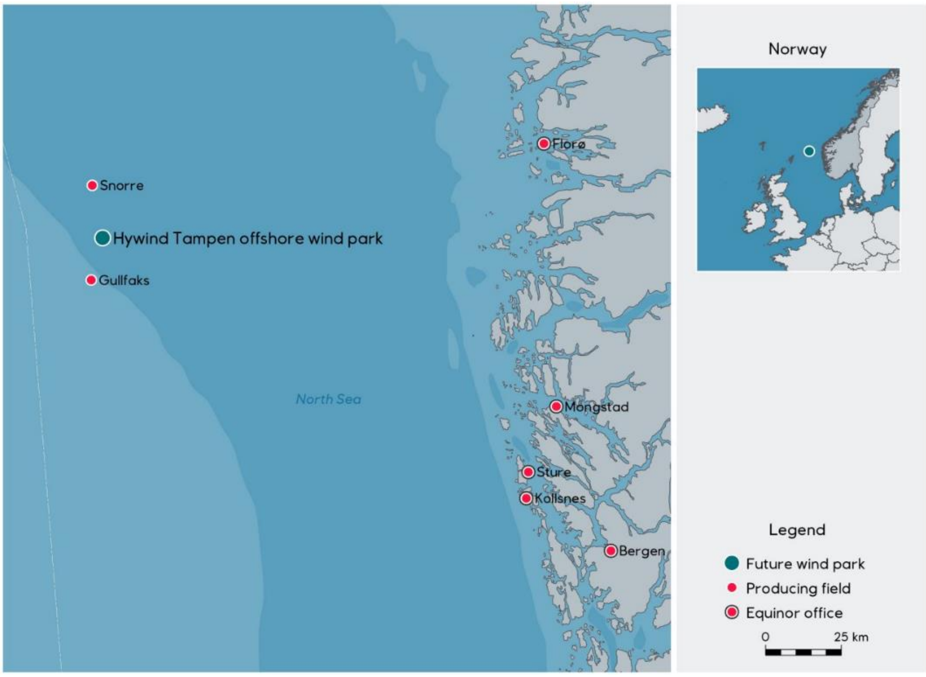

Figure 2-12. Map of Hywind Tampen offshore wind farm and Sorre and Gullfaks oil & gas platforms. *Source: Equinor, 2020*[128]

2.1.3.9 Sweden

Sweden has 56 offshore wind farm projects in various stages of development, about 200 MW was operational at the end of 2019[129] and three are either consented or have applied for consent.[130] Currently, Sweden does not have a dedicated offshore wind support system in place. The green certificates system run jointly with Norway is planned to be closed for new projects by 2021.[131] Sweden is awaiting informal state aid approval on alternatives presented to waive grid connection fees for offshore wind projects.[132] This is to revive offshore wind development in the country, which stalled in recent years due to the lack of a dedicated support system for offshore wind and low wholesale market prices that were deemed insufficient to build new plants without subsidies.

Two models to eliminate grid-connection costs are examined.[133] The first model moves the grid connection point to the offshore wind farm. This would make the Swedish national grid operator (Svenska Kraftnät) responsible for the planning, construction, and operation of the undersea connection cable, as well as all the connection costs. The second model provides wind power producers with subsidies to cover parts of the connection costs. This would only cover the undersea cable and transformers to create conditions more comparable to onshore wind plants.

[128] Equinor, 2020. Hywind Tampen: the world's first renewable power for offshore oil and gas. https://www.equinor.com/en/what-we-do/hywind-tampen.html

[129] WindEurope, 2020. Offshore Wind in Europe Key trends and statistics 2019. https://windeurope.org/about-wind/statistics/offshore/european-offshore-wind-industry-key-trends-statistics-2019/

[130] C4Offshore, 2020.Offshore wind farms in Sweden. https://www.4coffshore.com/windfarms/sweden/

[131] Wind Power Monthly, 2020. Sweden lines up 2021 subsidy stop. https://www.windpowermonthly.com/article/1663548/sweden-lines-2021-subsidy-stop

[132] Recharge News, 2019. Sweden waits for EU nod over rule change to revive offshore wind. https://www.rechargenews.com/wind/sweden-waits-for-eu-nod-over-rule-change-to-revive-offshore-wind/2-1-678625

[133] Recharge News, 2019. Sweden waits for EU nod over rule change to revive offshore wind. https://www.rechargenews.com/wind/sweden-waits-for-eu-nod-over-rule-change-to-revive-offshore-wind/2-1-678625

In October 2019, the Swedish navy put a full stop to a few offshore wind pipeline projects due to military concerns.[134]

2.1.3.10 UK

The UK Government Department for Business, Energy & Industrial Strategy (BEIS) is revising the CfD scheme for future auction rounds, including allocation round (AR) 4 expected in 2021, with a public consultation on the proposed changes running till the end of May 2020.[135] The review's objective is to encourage renewable energy support to deliver the government's 2050 net zero target, while minimising costs to consumers.

The key proposed changes to the CfD scheme include a proposed review of the pot structure for competing technologies and other aspects, for example:[136]

- The introduction of floating offshore wind as a separate eligible technology with its own administrative strike price, providing a distinction from fixed-bottom projects.
- A proposed separate Pot 3 for fixed-bottom offshore wind projects.
- A proposed link between the offshore renewable energy installation decommissioning regime with the CfD scheme.
- Non-delivery disincentive options (e.g. bid bonds).
- A proposed extension of the negative pricing rule, so that CfD generators are not subsidised when electricity prices are negative in the day-ahead hourly market.

The government intends to run a CfD allocation round in 2021 for all eligible technologies and to hold subsequent rounds every 2 years thereafter.

In addition, the Crown Estate launched its Round 4 offshore wind leasing round in September 2019, making available between 7 GW and 8.5 GW of new rights to the seabed.[137] Four bidding areas were identified (see Figure 2-13) and at least three will be made available for offshore renewable developments, each with a maximum of 3.5 GW and water depths up to 60 m, making them suitable for fixed bottom offshore wind. Prospective developers can identify and propose projects within these bidding areas. Round 4 consists of a three-stage tendering process with various evaluation criteria of prospective sites to evaluate the capability to deliver of the bidder and the project before determining the award based on option fees. The first project (Round 4) are expected to enter in an Agreement for Lease by 2021 with awarded sites to become operational towards the end of this decade.

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[134] OffshoreWindBiz, 2019. Swedish Armed Forces Shoots Down Vattenfall's Offshore Wind Farm Project https://www.offshorewind.biz/2019/10/21/swedish-armed-forces-shoots-down-vattenfalls-offshore-wind-farm-project/

[135] UK Government, 2020. Contracts for Difference (CfD): proposed amendments to the scheme 2020. https://www.gov.uk/government/consultations/contracts-for-difference-cfd-proposed-amendments-to-the-scheme-2020 ; Department for Business, Energy & Industrial Strategy (UK), 2020. Contracts for Difference for Low Carbon Electricity Generation Consultation on proposed amendments to the scheme. https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/885248/cfd-ar4-proposed-amendments-consultation.pdf

[136] OffshoreWind.biz, 2020. UK Extends Comment Period for Proposed CfD Changes. https://www.offshorewind.biz/2020/05/15/uk-extends-comment-period-for-proposed-cfd-changes/

[137] The Crown Estate (UK), 2019. Information memorandum: Introducing Offshore Wind Leasing Round 4. https://www.thecrownestate.co.uk/media/3378/tce-r4-information-memorandum.pdf

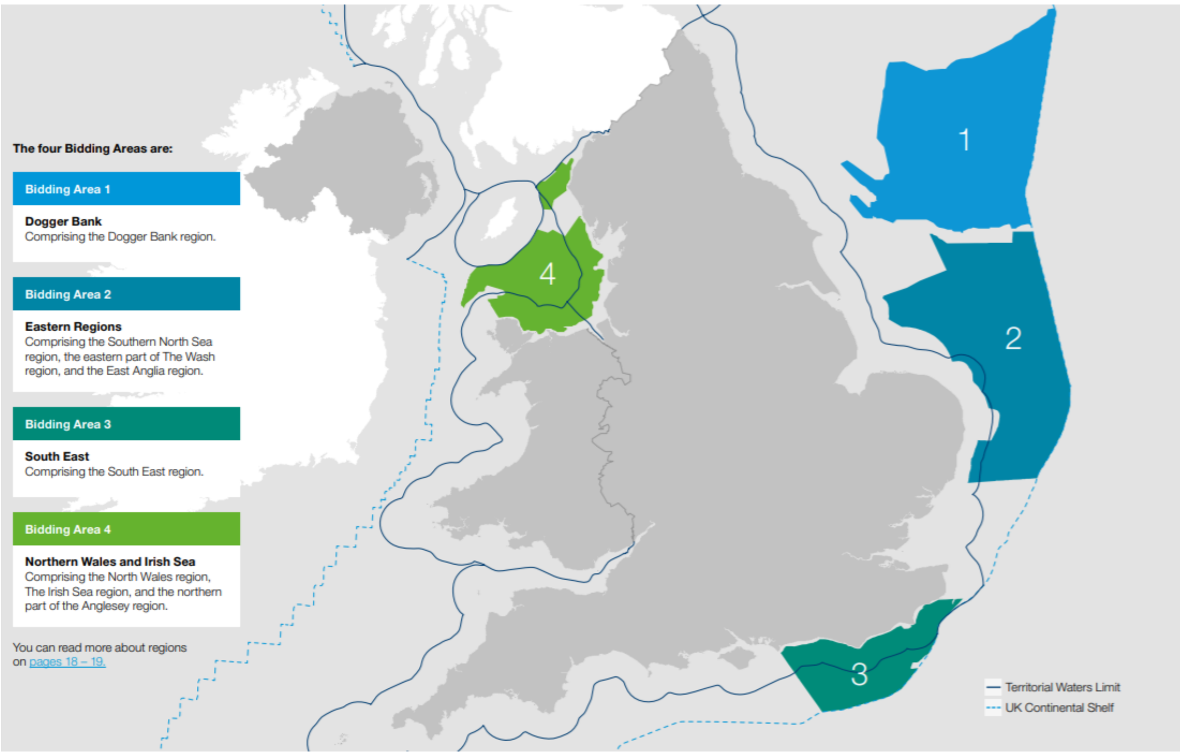


Figure 2-13. Four bidding areas for Round 4 leasing. *(Source: The Crown Estate, 2019)*[138]

Round 4 leasing introduces an extension of the lease terms to 60 years.[139] This would allow any wind farm repowering or replanting without new transmission infrastructure and would help reduce offshore wind cost. In addition, the Round 4 leasing aims at incentivising technological innovations through offering rental discounts on Round 4 projects that include innovation, enabling developers to propose hybrid projects (e.g. wind and interconnection), giving opportunities to developers for precommercial testing and demonstration of emerging offshore wind technologies such as floating, and working together with planners and various stakeholders to identify potential innovation locations (e.g. floating offshore wind location).

The Crown Estate Scotland plans to launch an offshore wind leasing round in Scotland in the near future (ScotWind Leasing of the seabed), which will follow after the publication of Marine Scotland's draft sectoral marine plan.[140]

[138] The Crown Estate (UK), 2019. Information memorandum: Introducing Offshore Wind Leasing Round 4. https://www.thecrownestate.co.uk/media/3378/tce-r4-information-memorandum.pdf

[139] The Crown Estate (UK), 2019. Information memorandum: Introducing Offshore Wind Leasing Round 4. https://www.thecrownestate.co.uk/media/3378/tce-r4-information-memorandum.pdf

[140] Crown Estate Scotland, 2019. ScotWind Leasing Update. https://www.crownestatescotland.com/media-and-notices/news-media-releases-opinion/scotwind-leasing-update

2.2 Financing and cost recovery of connections to shore in NSEC countries

2.2.1 Introduction

This section investigates the characteristics of financing and cost recovery for offshore wind farm connections to shore in NSEC countries and the UK that have developed schemes in place (see section 2.2.2). This results in a comparative overview table and figures that illustrate the differences in responsibilities and financing and cost recovery between the different adopted grid delivery models for offshore wind. Section 2.2.3 summarises any concrete and foreseen developments of grid delivery models for offshore wind in NSEC countries and the UK.

The selected grid connection regime or grid delivery model for offshore wind farms defines stakeholder roles and responsibilities during the different project phases. The grid delivery model determines who finances the grid connection and where the interface lies between a developer and the governing TSO, transmission asset owner (TAO), or offshore transmission owner (OFTO). The adopted regime balances cost to consumers and government control over planning and realisation timelines with de-risking of developers in the various stages of the project.[141]

The design of offshore wind farm connections and the selected grid connection regime in NSEC countries and the UK depends on the location of the wind farm and its distance to an onshore connection point. Within NSEC countries and the UK, multiple grid connection configurations have been applied, as indicated in section 2.1.3. Most of the installed offshore wind capacity to date is located relatively close to shore and connected to the onshore grid via alternating current (AC), either through direct connection of array cables, or through an AC offshore substation or offshore AC hub as currently under development in Belgium (MOG and MOG II, see section 2.2.3.1) and the Netherlands (Borssele Alpha see section 2.2.3.6). Using hub concepts reduces the number of cable corridors and landfall locations and increases redundancy compared to individual connections. Offshore connections over long transmission distances, such as those widely adopted in Germany (as offshore wind sites are located beyond the Waddensea), have been connected via direct current (DC) to optimise the transmission system in terms of costs and electrical losses.

Currently, HVDC technology for offshore transmission assets has only been applied in Germany where wind farms are connected to HVDC offshore substations through HVAC collector platforms. The latest developments are offshore wind farms located further offshore that will be connected through an offshore HVDC hub. This more standardised HVDC hub concept where wind farms can directly connect to is currently under development in Germany (see section 2.2.3.4) and the Netherlands (see section 2.2.3.6).[142] Available onshore grid capacity is an important prerequisite. In the Netherlands, the rollout of 10.6 GW of offshore wind farm capacity by 2030 is expected at landing points where sufficient onshore grid capacity is available in a timely manner. In Germany, large HVDC corridors are planned between North and South Germany to enable the integration of the continued rollout of offshore wind. The use of hub concepts can limit the number of landing points required as connections can be combined. Figure 2-14 describes currently applied and planned grid connection configurations.

[141] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. Available online: http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf

[142] Blixx Consultancy BV, 2019. Validation of Studies regarding the Grid Connection of Windfarm Zone IJmuiden Ver. https://offshorewind.rvo.nl/file/download/55040388/Report+-+Validation+Grid+Connection+Studies+IJmuiden+Ver+-+BLIX+Consultancy

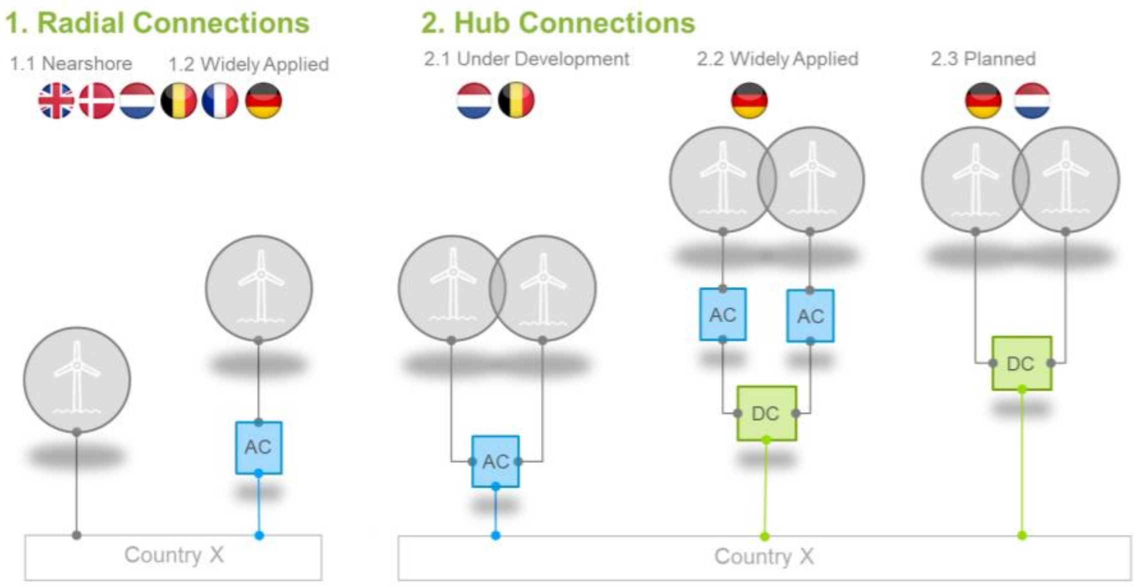


Figure 2-14. Overview of currently applied and planned grid connection configurations.
(Source: Guidehouse analysis)

2.2.2 Overview of current regimes for the connection to shore

There are two main grid delivery models for offshore wind farms, developer-built/decentralised and TSO-built/centralised as Figure 2-15 details.[143]

- Under the developer-built or decentralised grid delivery model, the offshore wind farm and offshore wind transmission assets fall under the responsibility of the developer; this represents a deep grid connection regime.
- Under the TSO-built or centralised grid delivery model, the TSO (or TAO) is responsible for the offshore wind transmission assets and connection of the offshore wind farm to the onshore grid. The developer is responsible for the wind farm development; this represents a shallower grid connection regime.

These models represent two ends of a spectrum on how responsibilities of construction and financing of offshore wind transmission assets are divided between the developer and the TSO or TAO. In NSEC countries and the UK, various models are adopted that combine responsibilities of the two main models as section 2.2.2.1 describes.

[143] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

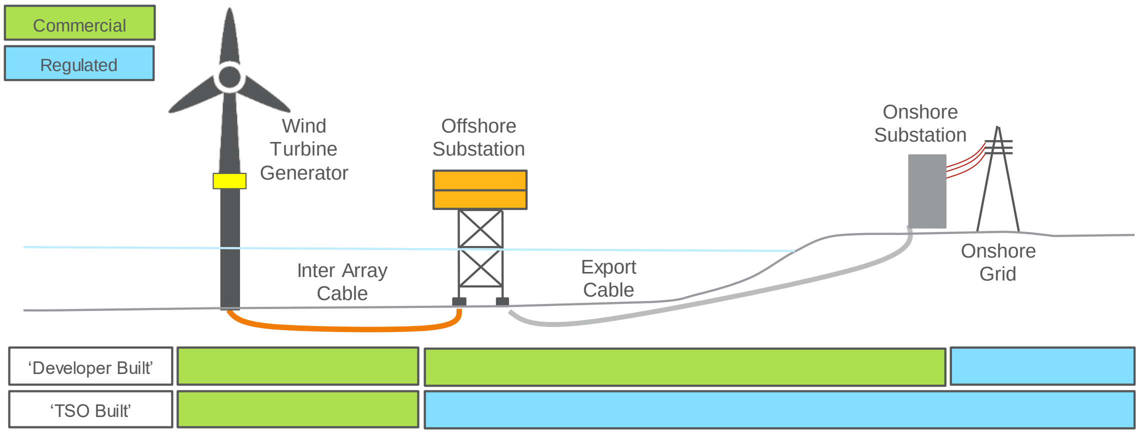


Figure 2-15. Schematic overview of main grid delivery models for offshore wind: developer-built (decentralised) and TSO-built (centralised). *(Source: Navigant, 2019)*[144]

This section presents grid delivery models currently adopted in NSEC countries and the UK, as well as any concrete plans. Section 2.2.2.1 presents the responsibilities implied by these models, section 2.2.2.2 presents the related financing and cost recovery model.

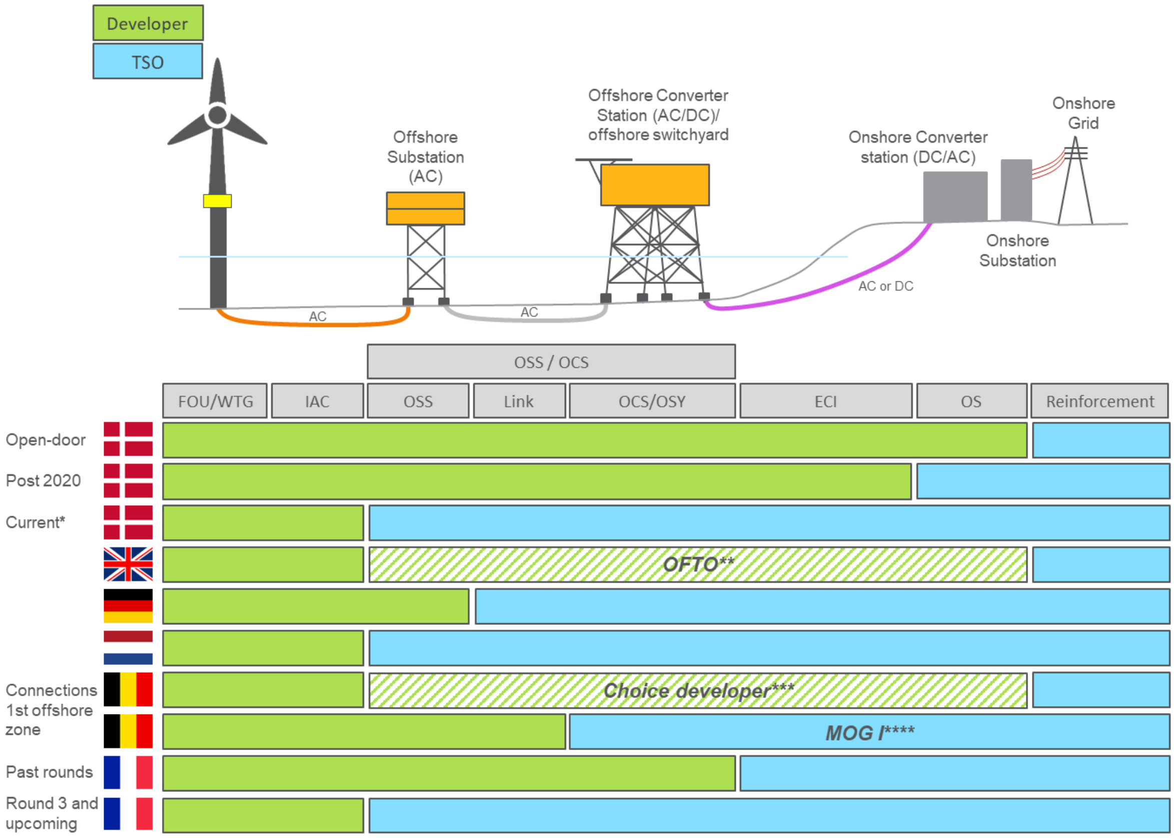
2.2.2.1 Allocation of responsibilities

The connection of wind farms to shore can include the following offshore wind transmission assets, depending on the configuration: offshore substation(s), offshore AC/DC converters, export cable(s) (either AC or DC), the onshore substation(s), and onshore DC/AC converters (see Figure 2-16). For each connection regime, responsibilities are divided between developers, state bodies, and TSOs/TAOs/OFTOs. In addition, the responsibility of potentially required onshore grid reinforcements needs to be assigned, Within NSEC countries and the UK, national governments have adopted various grid delivery models.

Figure 2-16 shows a schematic representation of grid development responsibility allocation for six European offshore wind markets. Not all asset types shown in the overview are applied in the countries considered. The UK is currently the only market with a full developer-built offshore grid delivery approach. In Denmark, the developer of the upcoming 800 MW-1,000 MW Thor offshore wind farm will be responsible for the offshore substation and export cable.[145] The grid delivery models in other NSEC countries with an offshore market have generally evolved from direct connections established and operated by commercial parties towards a TSO-built model where the TSO or TAO has a legal obligation or a government mandate to design, build, and operate the offshore grid. Other NSEC countries have no significant amount of offshore wind farm capacity in place yet and have a more decentralised model (increased grid delivery responsibilities for the wind farm developer), for example, Ireland's current system.

[144] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

[145] Danish Energy Agency, 2019. Thor offshore wind farm tender. https://ens.dk/sites/ens.dk/files/Vindenergi/brief_tender_for_thor_offshore_wind_farm_30march2019.pdf



Source: Navigant analysis
* Applicable from Thor tender, note that DK has two nearshore wind farms under development that will connect directly with their array cables to the onshore substation (see Developments in Denmark)
** OFTO: transmission assets sold to OFTO after commercial operation date (COD)
*** Developer reponsible for connection till OSS with the option to develop grid connection at a higher support payment (see Developments in Belgium)
****MOG = Modular offshore grid

Figure 2-16. Allocation of responsibilities for offshore wind transmission assets in applicable NSEC countries and the UK. *Sources: Navigant, 2019[146]; WindEurope, 2019[147]; IEA RTD, 2017[148]* . FOU = foundation, WTG = wind turbine generator, OSS = offshore substation, OCS = offshore converter station, OSY = offshore switch yard, ECI = export cable (either AC or DC), OS = onshore substation(s) and/or onshore DC/AC converters.

Each grid delivery model involves the same parties. However, their roles and responsibilities differ between different implementations of grid delivery models in NSEC countries and the UK. Table 2-5 details the roles and responsibilities of the stakeholders for the different grid delivery models in NSEC countries and the UK.

Although the European offshore energy market has developed for nearly 30 years, the roles and responsibilities between the key parties are still shifting between governmental agencies, government-owned parties, and commercial parties in established markets. A recent example is the Thor offshore wind farm in Denmark, which shifts the responsibility of the offshore wind transmission assets (offshore substation and export cable) to the developer. This is contrary to previous tenders for

[146] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. Available online: https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

[147] WindEurope, 2019. Industry position on how offshore grids should develop. https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Industry-position-on-how-offshore-grids-should-develop.pdf

[148] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. Available online: http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf

wind farms, such as Kriegers Flak and Horns Rev 3, where TSO Energinet developed the offshore wind transmission assets. Another example is the expanded role of TSO RTE in France for the planned Dunkirk offshore wind farm where RTE, instead of the developer, will develop the offshore wind transmission assets. A government can freely decide upon and revise their adopted grid delivery model and a range of different considerations are likely to influence this decision. For example, in the UK, Ofgem announced in February 2020 that it will explore whether a more coordinated offshore transmission system could reduce both financial and environmental costs, as it does not deem individual radial connections sensible and acceptable for consumers to allow for projected growth of offshore wind capacity.[149]

[149] Ofgem (UK), 2020. Ofgem decarbonization programme action plan. https://www.ofgem.gov.uk/system/files/docs/2020/02/ofg1190_decarbonisation_action_plan_web.pdf

Table 2-5. Overview of responsible parties for the activities in the different phases of offshore wind farm and grid connection development for the applicable NSEC countries and the UK. *(Sources: IEA, 2017[150], Navigant, 2019[151], Hogan Lovells, 2019[152], National references[153])*

Project phase	Responsibility	Description	Grid delivery model approaches					
			TSO-built[154] Belgium	TSO-built/ Developer-built[155] Denmark	TSO-built[156] France	TSO-built Germany	TSO-built Netherlands	Developer-built UK
Pre-development	**Zone selection**	Selection of location of offshore zone wherein wind farm sites (including transmission assets) could be developed, as well as identification and appointment of exclusion zones (e.g. military, shipping, fishing, etc.)	Minister for the North Sea	DEA (Danish Energy Agency)	French government	BSH (Maritime Authority)	RVO (Dutch Enterprise Agency)	The Crown Estate

150 IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. Available online: http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf

151 Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. Available online: https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

152 Hogan Lovells, 2019. Offshore Wind Worldwide Regulatory Framework in Selected Countries. Available online: https://www.hoganlovells.com/~/media/germany_folder-for-german-team/artikel/2020_offshorewindworldwide.pdf?la=en

153 See references in Table 2-6

154 Under the first offshore phase offshore wind grid connections have evolved from single lines per wind farm where the developer could opt to build the transmission assets to the more recent farms that are connected to the Modular offshore grid where the developers are responsible for that part of the transmission assets to connect to the MOG and the MOG and remainder of the offshore transmission assets fall under the responsibility of the TSO Elia. The planned 2nd phase still need to be adopted in a Royal Decree.

155 For Danish open-door procedure, developers are responsible for all responsibilities except for final selection of onshore grid connection point and any required onshore grid reinforcements. For the latest upcoming tenders (Thor) Denmark is transitioning from a TSO-built model to a more developer-built model.

156 For round 1 and 2 RTE develops and build the assets except the offshore substation. Following a change of law in 2018, the TSO now also finances the connections, which was previously allocated to the developers.

Project phase	Responsibility	Description	Grid delivery model approaches					
			TSO-built[154]	TSO-built/ Developer-built[155]	TSO-built[156]	TSO-built	TSO-built	Developer-built
			Belgium	Denmark	France	Germany	Netherlands	UK
	Site selection	Selection of location of offshore wind farm site (including transmission assets) within the selected offshore zone	*Previous/Current:* Developer *Planned:* Federal Minister of Energy	*Open door:* Developer *Current/Upcoming:* DEA	French government	*Transitory tenders (2017/2018):* Developer *From 2021 onwards:* BSH	RVO	Developer
	Offshore wind farm transmission asset planning	Timing of offshore wind transmission asset development	*Previous/Current:* Elia/ Developer *Planned:* Elia	*Current/Upcoming:* DEA/ Energinet	RTE	TSO (TenneT and Amprion in North Sea, 50 Hertz in Baltic Sea)/ Developer	TenneT TSO B.V./RVO	Developer
Development	**Offshore wind farm transmission asset consents/ permits – application**	Consents for the offshore wind transmission assets (including environmental assessment and any required leases or licences)	*Previous/Current:* Developer to the Federal Minister of Energy *Planned:* Elia	*Open door:* Developer *Current:* DEA/ Energinet *Upcoming:* DEA/ Developer	RTE	TSO/Developer	RVO	Developer
	Financing	Financing of offshore wind transmission assets	*Previous/Current:* Developer/Elia *Planned:* Elia	*Current:* Energinet *Upcoming:* Developer	RTE	TSO	TenneT TSO B.V.	Developer/OFTO
	Final selection of onshore grid connection point	Final decision on onshore grid connection point	Elia	Energinet	RTE	TSO	TenneT TSO B.V.	NETSO (National Electricity TSO)

Project phase	Responsibility	Description	Grid delivery model approaches: TSO-built[154] Belgium	TSO-built/ Developer-built[155] Denmark	TSO-built[156] France	TSO-built Germany	TSO-built Netherlands	Developer-built UK
	Functional design offshore wind farm transmission assets	High level design of the functional requirements and specs of transmission assets beyond grid codes and applicable standards (e.g. voltage level, capacity, cable corridor, offshore substation location, landing points, shared assets if applicable)	*Previous/Current:* Elia/Developer *Planned:* Elia	*Open door:* Energinet/ developer *Horns Rev 3 and Kriegers Flak:* energinet.dk *Thor:* Energinet/ developer	*Previous: RTE/d\Developer* *Upcoming:* RTE	TSO/Developer	TenneT TSO B.V.	NETSO/Developer
Construction	**Detailed design offshore wind farm transmission assets**	Detailed design of offshore wind transmission assets (e.g. full technical definition of transmission assets, installation methodology, construction timeline, etc.)	*Previous/Current:* Developer/Elia *Planned:* Elia	*Open door:* developer *Horns Rev 3 and Kriegers Flak:* Energinet *Thor:* Developer	RTE	Developer/TSO	TenneT TSO B.V.	Developer/OFTO
	Offshore wind farm transmission asset construction	Construction and commissioning of transmission assets	*Previous/Current:* Developer/Elia *Planned:* Elia	*Current:* Energinet *Upcoming:* Developer	RTE	TSO	TenneT TSO B.V.	Developer/OFTO
O&M	**Ownership and maintenance**	Ownership and maintenance of offshore wind transmission assets (including decommissioning)	*Previous/Current:* Developer/Elia *Planned:* Elia	*Current:* Energinet *Upcoming:* Developer	RTE	TSO	TenneT TSO B.V.	OFTO
	Operation	Operation of offshore wind transmission assets	*Previous/Current:* Developer/Elia *Planned:* Elia	*Current:* Energinet *Upcoming:* Developer	RTE	TSO	TenneT TSO B.V.	NETSO

Project phase	Responsibility	Description	Grid delivery model approaches: TSO-built[154] Belgium	TSO-built/ Developer-built[155] Denmark	TSO-built[156] France	TSO-built Germany	TSO-built Netherlands	Developer-built UK
Onshore grid reinforcements	**Responsibility onshore grid reinforcement**	Planning, specification, consenting (EirGrid) and construction (ESB Networks) of required reinforcements in the onshore grid to facilitate the infeed of offshore wind energy	Elia	Energinet	RTE	TSO	TenneT TSO B.V.	NETSO
Ownership boundary			Past: onshore or offshore Current/future: MOG offshore	Open-door: onshore Previous/near shore: offshore New tenders: offshore	Offshore	Offshore	Offshore	During construction: onshore During operation: offshore

2.2.2.2 Financing and cost recovery models

The mechanism for the recovery of the costs needs to be established after defining the responsible parties for the construction and financing of the offshore wind transmission assets. Financing offshore wind transmission assets consists of three key elements: construction, onshore and offshore operations and maintenance (O&M), and (in some cases) onshore grid reinforcements. Descriptions of the generic developer-built and TSO-built models form the basis for our country-level analysis. We also provide the country-specific regulations for the applicable NSEC countries and the UK.

Figure 2-17 summarises the main principles for offshore wind transmission asset financing and cost recovering for the onshore grid reinforcement (if applicable), construction, and O&M phases. A TSO-built model presents a shallow cost regime and a developer-built model represents a deep cost regime.

	Conditional: Onshore Grid Reinforcement	Construction	Operation & Maintenance
TSO-built	• TSO finances onshore grid reinforcements. • Cost recovery via regulated transmission tariffs for electricity consumers.	• TSO finances construction of on- and offshore assets. • Costs are recovered through government subsidy or via regulated transmission tariffs for electricity consumers.	• TSO pays grid operation and maintenance costs. • Costs are recovered through government subsidy or via regulated transmission tariffs for electricity consumers.
Developer-built	• TSO finances onshore grid reinforcements. • Cost recovery via regulated transmission tariffs for electricity consumers.	• Either the offshore wind farm developer or OFTO can finance the grid connection • Offshore wind farm developer sells the assets to an OFTO via a competitive tender whereas OFTO recovers its investments via Tender Revenue Stream from onshore TSO. The offshore wind farm developers pay a tariff which partly covers the revenues received by the OFTO.	• TSO is responsible for system operation whereas OFTO maintains the transmission assets. • OFTO recovers its investments via Tender Revenue Stream from TSO. The offshore wind farm developers pay a tariff which partly covers the revenues received by the OFTO.

Source: Navigant analysis

Note: For onshore grid reinforcements, it is more complicated to trace part of the tariffs that are linked to offshore wind

Figure 2-17. Financing and cost recovery mechanism for offshore wind transmission assets for generic developer-built and TSO-built gird delivery models for offshore wind. *(Source: Navigant, 2019)*[157]

Figure 2-18 and Figure 2-19 detail financial and supply flows for the TSO-built and UK OFTO (developer-built) grid delivery models for offshore wind. Table 2-6 describes the exact cost recover mechanism for each NSEC country and the UK.

[157] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

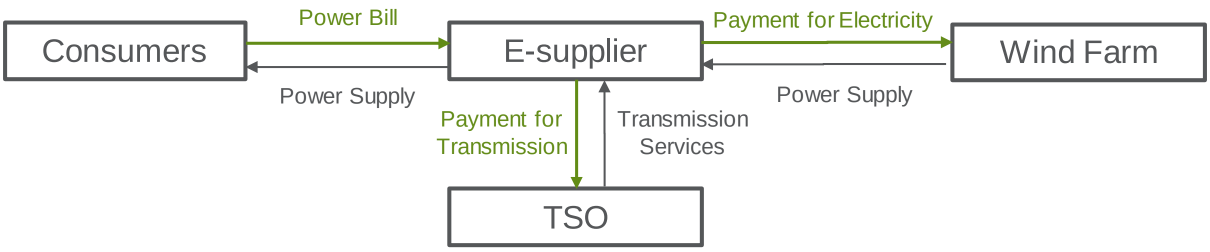


Figure 2-18. High level schematic overview of financial and supply flows in a TSO-built grid delivery model. Cost are recovered through a specific levy on the consumers' power bill or through the network tariffs. *(Source: Navigant, 2019)*[158]

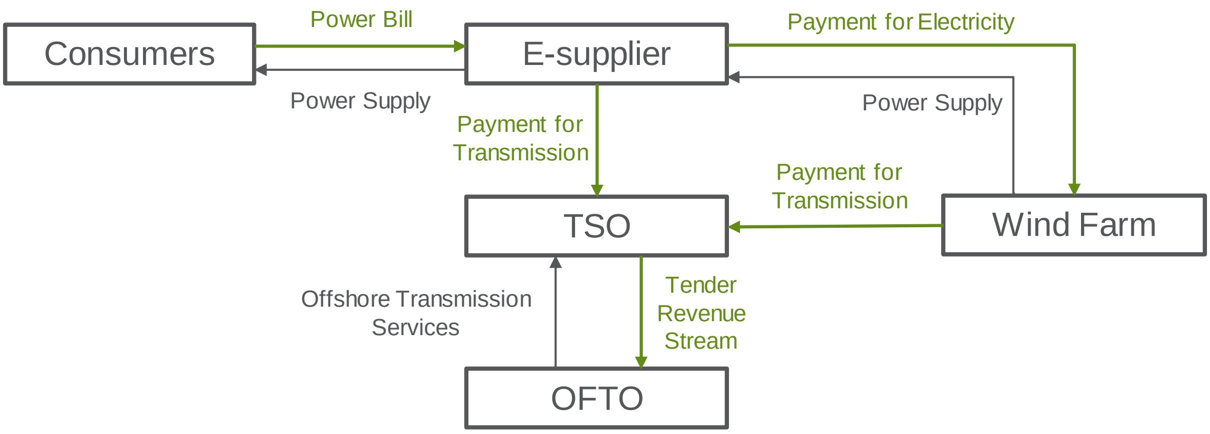


Figure 2-19. High level overview of financial and supply flows in the UK OFTO model. *(Source: KPMG, 2014)*[159]

[158] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

[159] KPMG. (2014). Offshore transmission: an investor perspective Update report. OFGEM. https://www.ofgem.gov.uk/publications-and-updates/offshore-transmission-investor-perspective-update-report

Table 2-6. Cost recovery mechanisms for offshore transmission assets per NSEC country and the United Kingdom.

Country	Cost recovery	Reference
Belgium	Under the current and future regime, the TSO Elia is responsible for the cost for offshore grid connection assets, such as the Modular offshore grid and the plans for the MOG II, and is recovered through the grid levy included in consumers' electricity tariffs.	*CREG, 2018*. Nota over het ondersteuningsmechanisme voor de bouw van offshore windmolenparken na 2020. https://www.creg.be/sites/default/files/assets/Publications/Notes/Z1880NL.pdf *Hogan Lovells, 2019*. Offshore Wind Worldwide Regulatory Framework in Selected Countries. https://www.hoganlovells.com/~/media/germany_folder-for-german-team/artikel/2020_offshorewindworldwide.pdf?la=en *CREG, 2018*. Publiek raadplegingsdocument. https://www.creg.be/sites/default/files/assets/Consult/2018/1718/PRD1718NL.pdf
Denmark	Denmark's regulatory regime for onshore investments also applies to offshore grid investments by the TSO without any adjustment; costs are recovered through the network tariffs. If the developer finances the grid connection, as will be the case with the Thor wind farm, costs are recovered through a Public Service Obligation (PSO) fee for end-consumers.	*PROMOTioN, 2019.* D7.6 Financing framework for meshed offshore grid investments. https://www.promotion-offshore.net/fileadmin/PDFs/D7.6_Financing_framework_for_meshed_offshore_grid_investments.pdf *Danish Energy Agency, 2015*. Danish Experiences from Offshore Wind Development. https://ens.dk/sites/ens.dk/files/Globalcooperation/offshore_wind_development.pdf
France	The costs for developing and building the offshore wind farm offshore and onshore grid connections are included in RTE's regulated asset base financing scheme and recovered through the consumer's energy bill through the TURPE (Tariff d'Utilisation des Reseaux Publics d'Electricite).	*Hogan Lovells, 2019*. Offshore Wind Worldwide Regulatory Framework in Selected Countries. https://www.hoganlovells.com/~/media/germany_folder-for-german-team/artikel/2020_offshorewindworldwide.pdf?la=en *WindEurope, 2019*. Industry position on offshore grids should develop. https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Industry-position-on-how-offshore-grids-should-develop.pdf
Germany	Until 2019 costs for offshore transmission assets were recovered through grid tariffs. From 2019, the cost for connections for offshore wind are recovered through the offshore surcharge on the electricity bill of consumers as defined in Section 17f of the Energy Industry Act (EnWG). The offshore grid surcharge was introduced in 2013 to create a reliable framework for the expansion of offshore wind energy and transparently show the them as a separate cost item. In 2019, the surcharge for residential customers was 0.416 ct/kWh.	*BMWi, 2020*. State-imposed components of the electricity price. https://www.bmwi.de/Redaktion/EN/Artikel/Energy/electircity-price-components-state-imposed.html

Country		Cost recovery	Reference
	Ireland	Under the more decentralised grid delivery model, onshore grid reinforcements are recovered through the grid tariffs (TNuOs), offshore grid developments can be constructed by the developer (contested) and recovered through the PSO levy for end-consumers, or by the TAO/TSO and recovered through grid tariffs.	*Electricity Ireland, 2019*. What is the PSO levy and how much is it? https://www.electricireland.ie/residential/help/billing/is-thepso-levy-increasing Household Energy Price Index, 2020. www.energypriceindex.com
	Netherlands	TenneT receives compensation for developing the offshore grid, which the government pays out of the ODE levy on consumer tariffs (opslag duurzame energie).	*Rijksoverheid, 2020*. WAT KOST HET NET OP ZEE?. https://windopzee.nl/onderwerpen-0/wind-zee/kosten/kosten-net-zee/
	Norway	The regulatory framework for offshore interconnectors is the same as for Statnett's onshore investments the costs are recovered through the grid tariffs. Norway does not have a specific framework for offshore wind farm transmission assets.	*PROMOTioN, 2019.* D7.6 Financing framework for meshed offshore grid investments. https://www.promotion-offshore.net/fileadmin/PDFs/D7.6_Financing_framework_for_meshed_offshore_grid_investments.pdf
	Sweden	TSO Svenska Kraftnät is responsible, at national level, to plan and upgrade the grid when necessary. Costs are recovered through the network tariffs. Sweden does not have a specific framework for offshore wind farm transmission assets.	*WindEurope, 2019*. Industry position on offshore grids should develop. https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Industry-position-on-how-offshore-grids-should-develop.pdf
	United Kingdom	Offshore wind transmission assets are sold by developers through a competitive tender to an OFTO for operation once the construction of the offshore transmission assets is completed. After taking over the ownership of the transmission assets, an OFTO recovers its investments mainly through a Tender Revenue Stream (TRS). Figure 2-19 summarises financial and supply flows between consumers, suppliers, NETSO, and OFTO during wind farm operation.	*Navigant, 2019*. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

2.2.3 Overview on the planned regimes for the connection to shore

The following sections detail the ongoing developments in grid connection regimes in the applicable NSEC countries and the UK.

2.2.3.1 Belgium

During the first offshore concession phase of Belgian offshore wind, the responsibility of the radial grid connection of the offshore wind farms lay with the developers.[160] The developer-led approach with radial connections to the onshore 150 kV substations (Slijkens and Zeebrugge) was adopted for the offshore wind farms C-Power, Belwind, Northwind, and Nobelwind. Discussions regarding techno-economic efficiency of radial connections started investigations in the potential of a shared connection for the remaining five concessions (Norther, Rentel, Seastar, Mermaid, and Northwester II).[160]

The Government Agreement from December 2012 states TSO Elia's responsibility regarding a "power plug at sea."[160] In 2011, Elia developed the vision for the offshore transmission grid infrastructure that had to be revised due to various challenges, resulting in Norther's application for an individual grid connection in 2014. In October 2014, Elia was tasked in the Government Agreement to develop a cost-efficient shared offshore infrastructure for offshore wind farms to balance cost, capacity, and timing to deliver, which resulted in the development of the Modular Offshore Grid (MOG I). The Rentel wind farm applied for an individual grid connection in 2015, which was approved with the option to transfer part of the transmission assets to Elia. In 2017, the Belgian Official Gazette published electricity law's revision to ensure a legal framework for the MOG.

The MOG is located 40 km offshore from Zeebrugge and will connect a total of ~1 GW (Rentel, Seastar, Mermaid, and Northwester 2 wind farms) by the end of 2020. The MOG was inaugurated at the end of 2019. It consists of an offshore switchyard with a 220 kV substation on a platform. Two 220 kV subsea cables connect the platform to the onshore substation of Stevin.[161] Figure 2-20 details the different connection regimes for the offshore wind farms in the first concession, including the offshore switch yard (MOG).

[160] Dutch Regulatory Authority for Electricity and Gas (CREG), 2018. Public Consultation Document 1718 - Draft Decree amending the Decree (Z) 141218-CDC-109/7 establishing the tariff methodology for the electricity transmission network and the electricity grids with a transmission function (Publiek raadplegingsdocument (PRD)1718 - Ontwerpbesluit tot wijziging van het besluit (Z)141218-CDC- 109/7 tot vaststelling van de tariefmethodologie voor het transmissienet voor elektriciteit en de elektriciteitsnetten met een transmissiefunctie). https://www.creg.be/sites/default/files/assets/Consult/2018/1718/PRD1718NL.pdf

[161] Elia Group, 2020. Modular offshore grid. https://www.elia.be/en/infrastructure-and-projects/infrastructure-projects/modular-offshore-grid

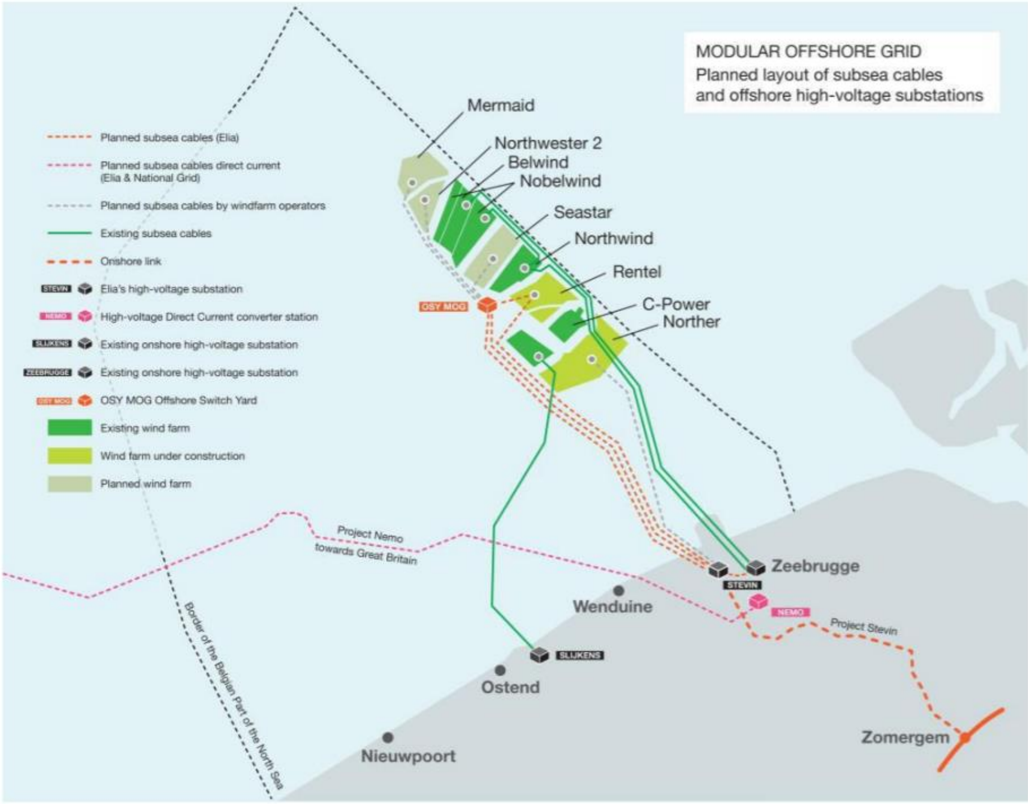


Figure 2-20. Schematic of the wind farms part of the first offshore concession with their respective connection regimes, including the offshore switch yard MOG. *Source: Elia, 2020*[162]

Elia is planning a MOG II (Modular Offshore Grid Extension) that would connect about 2 GW of future wind farms from the newly appointed offshore zones to shore through 220 kV AC cables to the new transmission corridor Stevin-Avelgem, which is reinforcing the onshore grid (see section 2.1.3.1).[163]

2.2.3.2 Denmark

Denmark has had several offshore grid delivery models in place, including an open-door policy and a TSO-built model. Denmark was an early adopter of a TSO-built model, whereby the TSO (Energinet) is responsible for the necessary offshore transmission assets.[164] For its latest planned tenders starting from Thor, a new, more a developer-led model for offshore wind transmission assets will be adopted.[165]

The Thor wind farm will be located in the North Sea west of Nissum Fjord 20 km from the shore.[166] Under the new grid delivery model, the Danish TSO Energinet will provide a new nearshore 220 KV

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162 Elia Group, 2020. Modular offshore grid. https://www.elia.be/en/infrastructure-and-projects/infrastructure-projects/modular-offshore-grid

163 ENTSO-E, 2018. Project 120 - MOG II: connection of up to 2 GW additional offshore wind Belgium https://tyndp.entsoe.eu/tyndp2018/projects/projects/120

164 IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. Available online: http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf

165 Energinet, 2019. THOR OFFSHORE WIND FARM - Market dialog November 25, 2019 - Grid connection https://ens.dk/sites/ens.dk/files/Vindenergi/6_thor_grid_connection.pdf

166 Hogan Lovells, 2019. Offshore Wind Worldwide Regulatory Framework in Selected Countries. https://www.hoganlovells.com/~/media/germany_folder-for-german-team/artikel/2020_offshorewindworldwide.pdf?la=en

onshore substation and be responsible for the onshore substation and the required transmission line to the inland grid. The developer will be responsible for offshore transmission assets (Figure 2-21).

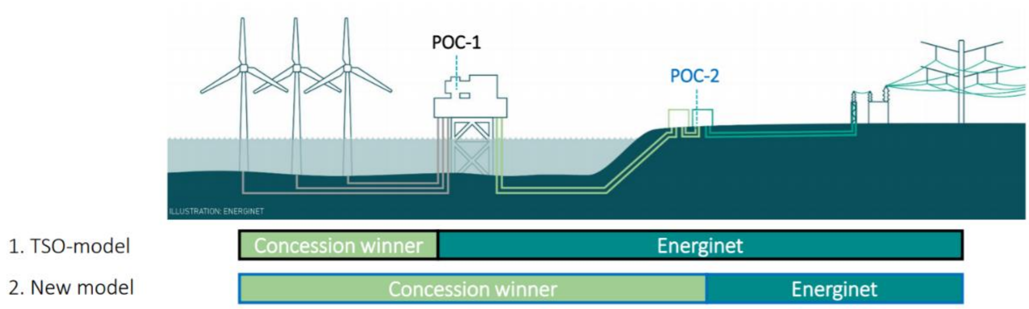

Figure 2-21. Schematic of previous TSO-built model and new model adopted for the upcoming Thor tender. *POC = point of connection. (Source: Energinet, 2019)*[165]

Energinet has specified that the developer construct the functional design and operational requirements of the offshore wind transmission assets.[165] Energinet will also use a housed GIS solution for its nearshore substations.

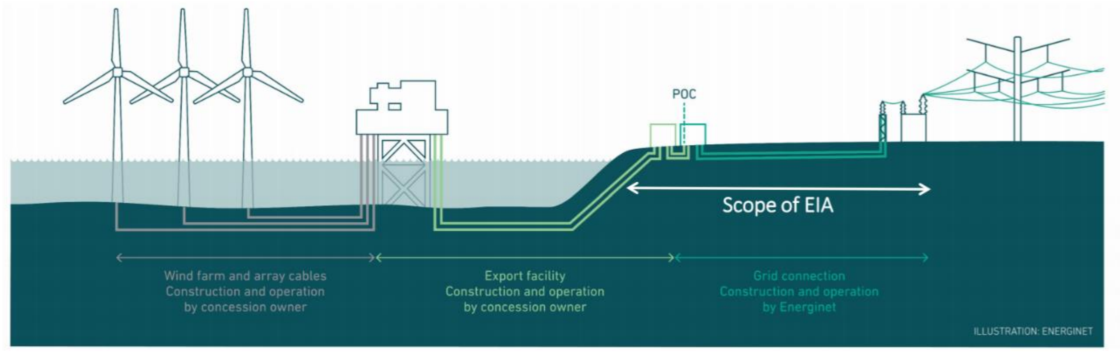

Figure 2-22. Schematic of scope and division of responsibilities under the new grid delivery model in Denmark. *Source: Energinet, 2019*[165]

The two nearshore tender projects, the 350 MW Vesterhav Syd and Nord in Jutland, located 9 km offshore, will be connected with 60 kV array cables by the developer Vattenfall to the new 150 kV substation owned by Energinet (Figure 2-23).[167,168]

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[167] Vattenfall, 2018. Vesterhav Syd and Nord will strengthen the electricity grid in West Denmark. https://group.vattenfall.com/press-and-media/news--press-releases/newsroom/2018/vesterhav-syd-and-nord-will-strengthen-the-electricity-grid-in-west-denmark

[168] 4COffshore, 2020. Vattenfall moves Vesterhav turbines. https://www.4coffshore.com/news/vattenfall-moves-vesterhav-turbines-nid16753.html

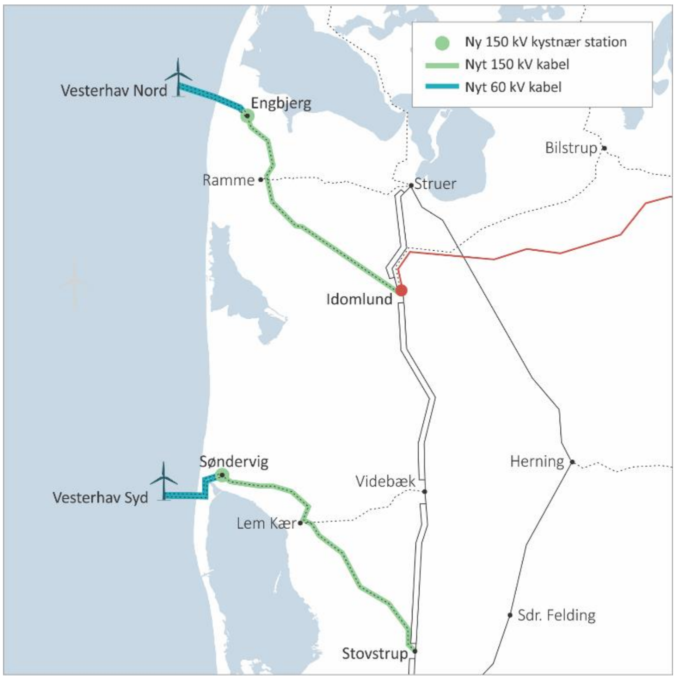

Figure 2-23. Schematic of the grid connection and responsibilities for the nearshore wind farms. *(Source: Vattenfall, 2018)*[167]

In addition to the developer-led open-door projects, the nearshore wind farms, and the upcoming tenders, Denmark has great interest in hybrid projects as part of offshore transmission asset infrastructure. As section 2.1.3.2 highlights, Denmark has two ongoing developments in this space: Kriegers flak and the two recently announced energy islands.

The Kriegers Flak hybrid connection is the ~400 MW AC grid system linking the Kriegers Flak (DK) wind farm (which is under construction) and the Baltic 2 (DE) wind farm. They are about 30 km apart from each other. An interface is required between the Danish and German electricity systems due to their phase difference through two serial voltage source converters (VSC) with onshore back-to back AC-DC DC-AC convertors.[169] In addition, voltage has to be adjusted from the 220 kV Danish system to the German 150 kV. Figure 2-24 provides the technical schematic.

[169] 50Hertz, 2020. KRIEGERS FLAK – COMBINED GRID SOLUTION. https://www.50hertz.com/en/Grid/Griddevelopement/Offshoreprojects/CombinedGridSolution

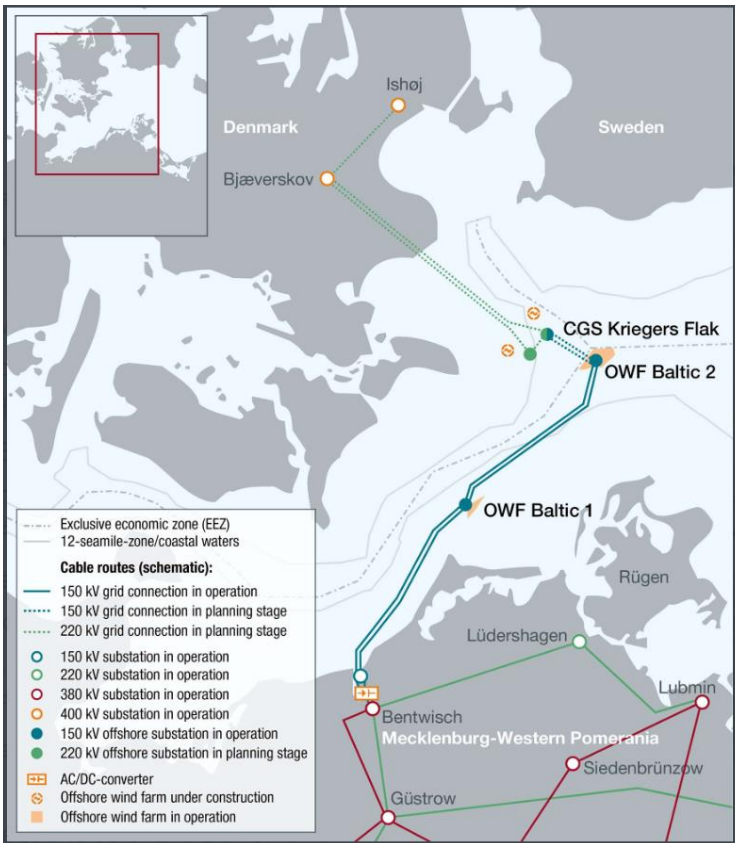

Figure 2-24. Schematic of the Kriegers Flak Combined Grid Solutions. *Source: 5oHertz, 2020*[170]

2.2.3.3 France

The French TSO has received more responsibility for the development of the offshore wind transmission assets for the Dunkirk wind farm compared to the initial grid connection regime in France. RTE plans to connect the wind farm with an offshore substation for the first time. The design of the substation is under development and is being determined, but the aim is to include other uses within the substation. In January 2019, RTE and the local Municipality of Dunkirk launched an explorative call for innovative ideas on how this electric substation could integrate other services, which resulted in over 165 ideas including considerations on environmental protection, tourism, and the energy transition.[171]

In addition to the developments at Dunkirk, the French regulatory CRE held a public consultation in March 2020 on the 10-year transmission network development plan from RTE, which included a consultation on the role of the state and RTE in the central planning and identification of offshore wind sites and the measures taken to optimise the costs for the development of offshore transmission assets for future offshore wind farms by RTE.[172]

[170] 50Hertz, 2020. KRIEGERS FLAK – COMBINED GRID SOLUTION. https://www.50hertz.com/en/Grid/Griddevelopement/Offshoreprojects/CombinedGridSolution

[171] RTE, 2020. Raccordement électrique du parc éolien en mer de Dunkerque. https://www.rte-france.com/fr/projet/raccordement-electrique-du-parc-eolien-en-mer-de-dunkerque

[172] Regulatory Energy Agency (France), 2020. Public consultation n ° 2020-005 of 5 March 2020 relating to the ten-year development plan for the RTE transmission network drawn up in 2019 (Consultation publique n°2020-005 du 5 mars 2020 relative au schéma décennal de développement du réseau de transport de RTE élaboré en 2019). https://www.cre.fr/Documents/Consultations-publiques/schema-decennal-de-developpement-du-reseau-de-transport-de-rte-elabore-en-2019

2.2.3.4 Germany

German offshore grid development happened through the existing offshore network development plan. That plan will be replaced in 2025 by an electricity grid development plan specifying the development of required onshore connection points and an area development plan (Flächenentwicklungsplan) by the BSH and agreed upon with the regulator BNetzA and all German TSOs (50Hertz, Aprion, TenneT, and TransnetBW).[173] The latest network plan was drafted in 2019 to include the connection of 20 GW offshore wind by 2030. Figure 2-25 details all offshore wind transmission asset developments in the German North Sea by TenneT.

Figure 2-25. Overview of offshore grid infrastructure in Germany. *Source: TenneT[174]*

Germany has farshore offshore wind farm developments in the German North Sea that require HVDC transmission assets to reduce losses related to transmission over long distances to shore. The TSO in the German North Sea, TenneT, is responsible for the HVDC transmission assets and AC connection to the HVAC substation (which falls under the responsibility of wind farms developers).[175] TSO TenneT is planning the use of offshore HVDC hubs for upcoming wind farm connections as first European TSO, see Figure 2-26.[176] This planned hub concept will be used for future wind farms

[173] WindEurope, 2019. Industry position on how offshore grids should develop. https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Industry-position-on-how-offshore-grids-should-develop.pdf

[174] TenneT, 2020. Offshore projects Germany. https://www.tennet.eu/index.php?id=2130&L=0

[175] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf

[176] TenneT, 2020. Energy from sea to land. https://www.tennet.eu/fileadmin/user_upload/Our_Grid/Offshore_Germany/2020_From_Sea_to_Land_Webversion.pdf

where the wind farms will directly connect to an offshore converter platform with 66 kV AC connections, eliminating the need for wind farm HVAC substations and the 155 kV connections. At the offshore converter platform, power is converted to HVDC and exported at 320 kV. The converter platform is connected to the onshore connection points through two HVDC sub-seabed cables. At the onshore substation, voltage is converted back to AC and connected to the 380 kV high voltage grid of TenneT.

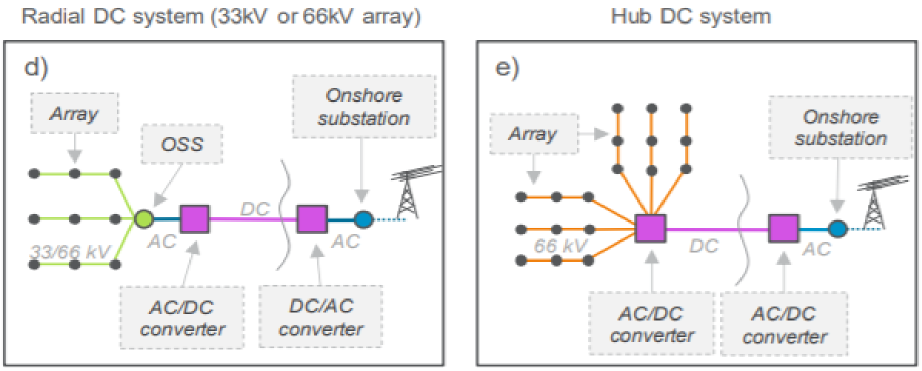

Figure 2-26. Schematic hub HVDC connection systems. *(Source: Navigant, 2019)*[177]

Next to the North Sea developments managed by TenneT, the TSO 50Hertz is responsible for connections in the Baltic Sea. Here HVAC transmission assets are employed.

Onshore grid constraints are a key challenge to the development of offshore wind in Germany; the grid is experiencing challenges and bottlenecks with transporting high levels of offshore wind from the North of Germany to the major load centres in the South.[178] There are delays in the reinforcement of the onshore transmission network, which has resulted in scaling back offshore wind targets in recent years. A coordinated and proactive grid development approach between the German TSOs has been emphasised to mitigate onshore grid constraints. In addition, North Sea offshore wind grid connections have experienced connection delays in the past due to ambitious timelines and the use of new HVDC concepts. The development of a coordinated offshore grid development plan and liability clauses are now included to limit TSO risk exposure. Compensations to developers and penalties for the TSO are now in place for delays in grid connection delivery.[179]

2.2.3.5 Ireland

The Irish Climate Action Plan targets at least 3.5 GW of offshore wind by 2030. The Department of Communications, Climate Action and Environment (DCCAE) tasked EirGrid (supported by Guidehouse) to analyse different options for suitable offshore wind grid delivery models for Ireland to achieve the 2030 targets and support developments beyond 2030.[180] There is an ongoing consultation on the grid delivery model. A developer-led model is in place currently.

Connecting 3.5 GW of offshore wind will require potential onshore grid reinforcements or upgrades. EirGrid performed a preliminary study in 2019 that assessed the potential hosting capacity of offshore

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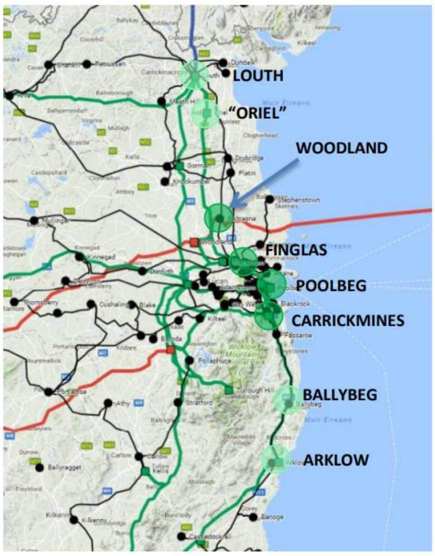
[177] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

[178] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. Available online: http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf

[179] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. Available online: http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf

[180] Department of Communications, Climate Action & Environment (Ireland), 2020. Consultation to Inform a Grid Development Policy for Offshore Wind in Ireland https://www.dccae.gov.ie/en-ie/energy/consultations/Pages/Consultation-to-Inform-a-Grid-Development-Policy-for-Offshore-Wind-in-Ireland.aspx

wind farms along the Irish East Coast.[181] Figure 2-27 indicates the identified onshore substations with available hosting capacity. EirGrid's study only considered individual connection additions and did not take into account cumulative effects of connecting multiple offshore wind farms, so the onshore connection capacities should not be treated cumulatively.



Substation	Opportunity for Offshore Wind Before significant works (MW)	Space at Substation
Louth	450	4 x bay space
Oriel (New 220kV substation)	400	New Substation
Woodland	>800	2 x bay space
Poolbeg North	600	2 x bays
Poolbeg South	>800	2 x bays
Finglas	>800	1x bays
Carrickmines	650	3 x bays
Ballybeg (New 220kV substation)	500	New Substation
Arklow	350	2 x bay Space

Figure 2-27. Potential connection locations for offshore wind farms along the east coast of Ireland. *(Source: EirGrid, 2020)*[181]

2.2.3.6 Netherlands

In the Netherlands, the TSO TenneT was appointed as offshore grid operator for the rollout of offshore wind farms until 2030. The Netherlands currently plans to meet 10.6 GW in 2030 (see also section 2). Under the Climate Agreement,[182] there is room to scale up the rollout of offshore wind due to increased levels of electrification in end-use sectors such as industry. TenneT indicated that its ability to integrate additional offshore wind capacity in the onshore grid before 2030 would be possible under specific conditions. TenneT indicates it could connect up to 3 x 2 GW of offshore wind farm connections (1 x 2 GW in 2029 and 2 x 2 GW in 2030), provided there is administrative support and acceptance that expanding capacity makes meeting the current roadmap more difficult.

In addition, TenneT plans to use a 2 GW HVDC platform solution for the IJmuiden Ver offshore wind farm connections, which will be the first HVDC connection for offshore wind farms in the Netherlands. HVDC is more preferable for this wind farm site due to its scale and distance to onshore connection points.[183] The proposed platform design is different from the HVDC platforms TenneT has applied in Germany as it allows for a direct connection of wind farm inter array cables (at 66 kV) instead of using an intermediate transformer platform (see Figure 2-28). The offshore converter platform converts the

[181] EirGrid, 2019. East Coast Generation Opportunity Assessment. http://www.eirgridgroup.com/site-files/library/EirGrid/East-Coast-Generation-Opportunity-Assessment.pdf

[182] Klimaatakkoord, 2019. Climate agreement chapter Electricity (Klimaatakkoord hoofdstuk Elektriciteit). https://www.klimaatakkoord.nl/elektriciteit/documenten/publicaties/2019/06/28/klimaatakkoord-hoofdstuk-elektriciteit

[183] Blix Consultancy EV, 2018. Validation of Studies regarding the Grid Connection of Windfarm Zone IJmuiden Ver. https://www.rvo.nl/sites/default/files/2019/04/Eindrapport%20Validatie%20netconcept%20IJmuiden%20Ver%20BLIX%20Consultancy.PDF

wind farm power to HVDC at 525 kV for export to an onshore converter station where power is converted back to HVAC.[184]

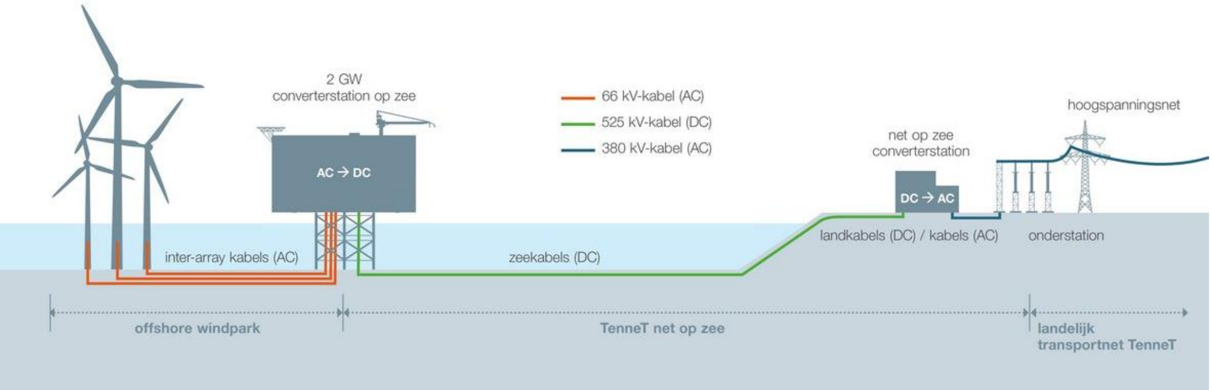


Figure 2-28: Schematic representation of 2 GW HVDC platform by TenneT for connecting the IJmuiden Ver wind farm area. *Source: TenneT, 2020*

TenneT is investigating options to increase the utilisation of the wind farm connection to IJmuiden Ver. The first option is connecting the IJmuiden Ver wind farm connection to a wind farm of Vattenfall in the UK, or connecting directly to the UK onshore grid to serve as a "Windconnector."[185,186] Using the wind farm connection as a hybrid asset allows for higher utilisation and reduces costs compared to individual radial solutions. Figure 2-29 provides a schematic representation of the Windconnector concept. As a second option, TenneT is investigating the connection of oil & gas platforms through the IJmuiden Ver wind farm connection.

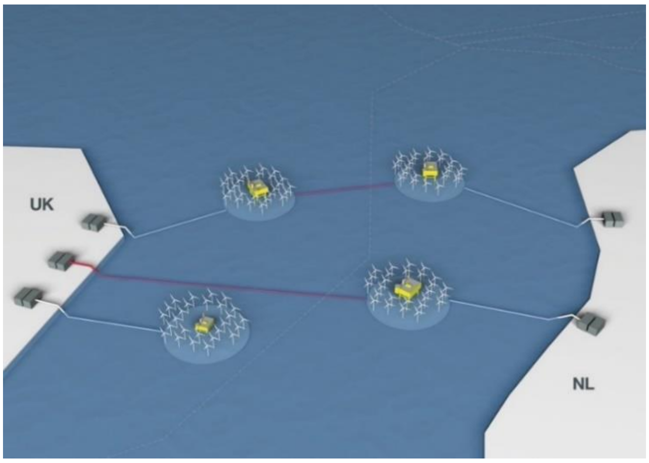


Figure 2-29. Schematic representation of "Windconnector" concept by TenneT where the IJmuiden Ver area would be connected to a UK wind farm (top), or the UK onshore grid (middle). *(Source: TenneT, 2020)*[186]

[184] TenneT, 2020. Net op zee IJmuiden Ver. https://www.tennet.eu/nl/ons-hoogspanningsnet/net-op-zee-projecten-nl/net-op-zee-ijmuiden-ver-beta/

[185] TenneT, 2018. enneT and Vattenfall to study potential Dutch and UK offshore wind farm connections https://www.tennet.eu/news/detail/tennet-and-vattenfall-to-study-potential-dutch-and-uk-offshore-wind-farm-connections/

[186] TenneT, 2020. Programme 2030. https://www.tennet.eu/our-grid/offshore-grid-netherlands/programme-2030/

2.2.3.7 Norway

Norway's offshore wind potential is mainly governed by floating offshore wind due to its specific bathymetry. A recent development is the plan for the first of its kind Hywind Tampen project, which will directly connect to the Snorre and Gullfaks oil & gas platforms,[187] (see section 2.1.3.8). The project was approved by the Norwegian Ministry of Petroleum and Industry in 2020 and will begin in Q3 2022. The project consists of 11 turbines at 8 MW that will be connected through a 66 kV dynamic inter-array cable system and will be located at a site with a water depth between 260 m and 300 m and approximately 140 km off the Norwegian coast.

2.2.3.8 Sweden

Sweden uses a developer-built grid delivery model where a developer is responsible for the offshore wind transmission assets up to the high voltage onshore connection point. However, until now, offshore wind developments in Sweden have been limited (see also section 2.1.3.9). In 2018, the Swedish Energy Agency investigated grid delivery models to accelerate offshore wind developers where the Swedish TSO, Svenska Kraftnät, would take on more transmission asset development responsibility.[188]

2.2.3.9 UK

Early 2020, Ofgem launched its decarbonisation programme action plan, which outlines a focus on "more effective coordination to deliver low cost offshore networks."[189] The UK will see a rapid increase in offshore wind capacity in the coming decade (see section 2) and Ofgem considers that individual radial offshore transmission links for these wind farms are unlikely to be economical, sensible, or acceptable for consumers and local communities. Ofgem announced it will investigate, together with government and industry, options for a more coordinated offshore transmission system for connecting offshore wind farms. It has tasked National Grid Electricity System Operator (NGESO), the responsible party for planning a coordinated and efficient transmission system, to assess options for coordination of offshore transmission, including analysis of costs and benefits (it started in spring 2020). In addition, Ofgem is discussing the potential for hybrid projects that combine interconnectors and wind farm connections.

In addition to the ongoing discussions on grid delivery regime for offshore wind, a HVDC connection is planned to connect offshore wind farms the UK for the first time, with the Dogger Bank wind farms who were awarded CfD support in 2019.[190] The Dogger Bank wind farms consist of three wind farm projects, Dogger bank A, B, and C, located around 130 km off the North East coast. Each project will have a capacity of up to 1.2 GW and will be constructed in three phases. Aibel and ABB will supply the offshore converter platform and HVDC power transmission system. Each project will have a single HVDC transmission link between the wind turbine arrays and the onshore transmission network.

[187] Equinor, 2020. Hywind Tampen: the world's first renewable power for offshore oil and gas. https://www.equinor.com/en/what-we-do/hywind-tampen.html

[188] WindEurope, 2019. How offshore grids should develop. https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Industry-position-on-how-offshore-grids-should-develop.pdf

[189] Ofgem, 2020. Ofgem decarbonization programme action plan. https://www.ofgem.gov.uk/system/files/docs/2020/02/ofg1190_decarbonisation_action_plan_revised.pdf

[190] SSE renewables and Equinor, 2020. Dogger Bank wind farm. https://doggerbank.com/

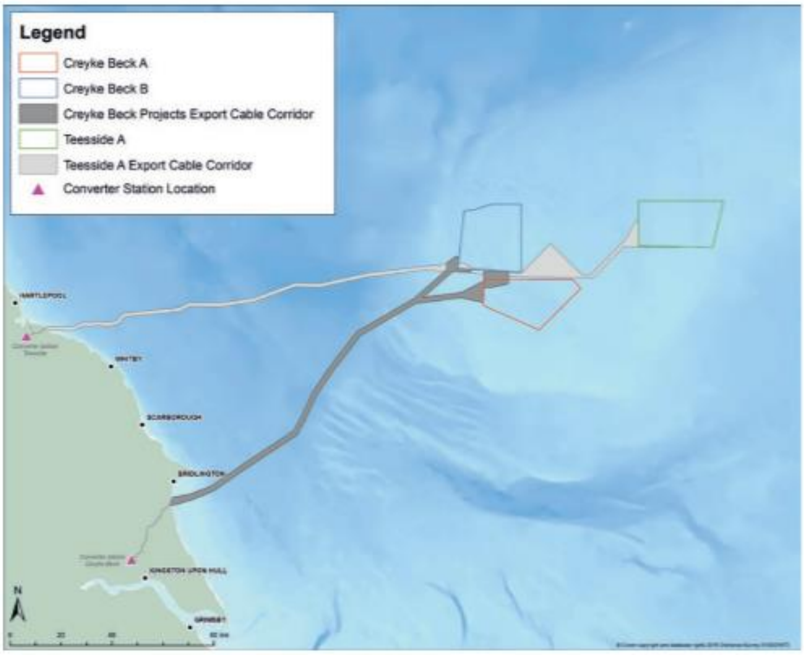


Figure 2-30. Dogger bank wind farms. *(Source: SSE renewables and Equinor, 2019)*[191]

2.2.3.10 International Developments

The trend of building wind farms further offshore and adopting increasing capacity ratings results in increased adoption of HVDC and hubs for the connection of offshore wind farms in NSEC countries and the UK. These developments also increase interest in international cooperation and sharing offshore energy between countries. An example of this is currently being investigated by the North Sea Wind Power Hub (NSWPH) consortium.[192] The consortium is working on a modular hub-and-spoke infrastructure concept to connect offshore wind through multiple central hubs of approximately 10 GW, which can be interconnected to the Netherlands (4 GW), Germany (6 GW), and Denmark (2 GW) to scale up offshore wind deployment while combining this with offshore interconnections.[193] The NSWPH is an offshore hybrid project and has received TYNDP-PCI status (project 335) as a first hub in the early development phase.[194]

Other ongoing developments for hybrid projects in NSEC countries and the UK include the Kriegers Flak combined grid solution between Denmark and German (section 2.1.3.2) and the WindConnector between the Netherlands and the UK (section 2.2.3.6).

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[191] SSE renewables and Equinor, 2020. Dogger Bank wind farm. https://doggerbank.com/

[192] North Sea Wind Power Hub, 2019, The Vision; The Hub-and-Spoke concept as modular infrastructure block to scale up fast. https://northseawindpowerhub.eu/wp-content/uploads/2019/07/Concept_Paper_2_The-Vision.pdf. Navigant has performed multiple studies for the NSWPH Consortium over the last few years: Navigant, Supporting the North Sea Wind Power Hub,
2019. https://www.navigant.com/experience/energy/2019/supporting-the-north-sea-wind-power-hub

[193] NSWPH, 2020. Modular Hub-and-Spoke: Specific Solution Options. https://northseawindpowerhub.eu/wp-content/uploads/2019/07/Concept_Paper_3-Specific-solution-options.pdf

[194] ENTSO-E, 2020. Project 335 – North Sea Wind Power Hub. https://tyndp.entsoe.eu/tyndp2018/projects/projects/335

2.3 Financing and cost recovery of interconnectors in NSEC countries

2.3.1 Introduction

This section provides insights into financing and cost recovery mechanism of interconnectors in NSEC countries and the UK. It summarises the various regimes that affect the development of interconnectors, including planning, ownership, cost recovery, and revenue models. In addition, this section describes the financing options and cost recovery models for the various investors before presenting lessons learned. It also highlights the perspectives of various stakeholders in the region.

2.3.2 Overview and analyses of applicable regimes

2.3.2.1 Planning regimes

In Belgium, Denmark, France, Germany, Luxembourg, the Netherlands, Norway, and Sweden, the regulators are responsible for planning of the grid in consultation with the TSO. Grid planning is done on the basis of the spatial or maritime planning that covers which locations OWPs will developed in the future. This plan also details where the interconnectors will be located. TSOs of these countries are responsible for design, build, finance, maintaining, and operating (DBFMO) the interconnectors, which they do by forming a Special Purpose Vehicle (SPV) with the TSO of the corresponding country.

The TSO is not responsible for planning in the UK and Ireland. There, private parties are allowed to approach the regulator (Ofgem) for an interconnector license. In case of a private incentive structure, the private party is responsible for DBFMO the interconnectors. In the UK, an interconnection is considered as a separate Transmission Operator (TO), it must coordinate with the System Operator (SO), i.e. National Grid Electricity for grid planning. In addition to private operators, the UK also has TSO-led interconnectors that are set up by National Grid Electricity through daughter/subsidiaries. These TSO-led interconnectors are treated the same as private interconnectors.

Table 2-7. Responsibility for DFBMO the interconnector

Country	Responsibility for DFBMO of the interconnector
Belgium	TSO
Denmark	TSO
France	TSO with exception of ElecLink*
Germany	TSO and private†
Ireland	TSO and private
Luxemburg	TSO
The Netherlands	TSO
Norway	TSO until now but private is possible
Sweden	TSO
UK	TSO and private

* ElecLink uses the Channel Tunnel for the interconnector cable
† NeuConnect, it will connect the UK and German grid

Table 2-8 Responsibility for connecting the OWP to the grid

Country	Responsibility for connecting the OWP to the grid
Belgium	OWP developer until now future connections will be by TSO
Denmark	TSO
France	TSO
Germany	TSO
Ireland	TSO
Luxemburg	NA
The Netherlands	OWP developer connects to the hub at the sea; TSO responsible for connecting hub to the onshore grid
Norway	TSO
Sweden	OWP developer
UK	Third party; OFTO regime

2.3.2.2 Cost recover regimes

CAPEX and OPEX recovery can occur through grid tariff, congestion rents, and the general budget. If a TSO owns an interconnector directly, recovery of CAPEX and OPEX will be through the TSO's general budget. In practice, interconnectors are always placed in SPVs and the general budget cost recovery only seems to apply to interconnectors that connect national grids within a country and not to international interconnectors discussed here.

All interconnectors derive their income from auctioning capacity in an open market with electricity traders, which constitute the asset's revenue. Auction revenue to the interconnector is a cost to the trader and is part of the congestion rent/revenue, which eventually is passed on to consumers. That is the case whether the interconnector is initiated by a private party with a TSO, if it was setup by a TSO, or if it was setup by independent private parties only. These auction revenue streams cover the repayment of CAPEX, OPEX, and interest and principal payments (if partially funded with debt). Any excess auction revenue is income and the ROI it generates may be capped. In some countries, the revenue is capped to encourage efficiency. It depends how the asset is regulated. But there are three interconnectors (all linking the UK) whose return is not limited by regulation: IFA, MOYLE, and East-West Interconnector.

Interconnectors can be realised by a TSO where the TSO is responsible for the DBFMO or a private party can initiate in interconnector, if linking to the UK. If the TSO sets up the interconnector, it can earn a regulated income sufficient to breakeven (which is the case in Denmark) or a regulated capped revenue. Alternatively, privately setup interconnectors can be regulated in two fashions: under a cap-and-floor system (UK and Belgium, Ireland, France, and Norway when linking with the UK) or on a merchant basis.

In 2014, the UK developed the cap-and-floor system, which was pragmatically adopted by TSOs from Belgium, Ireland, France, and Norway for interconnectors connecting with the UK. Ireland has adopted it completely. Under the cap-and-floor system, a developer—which can be a private developer (Greenlink) or between two TSOs (Celtic Connector)—sets up an SPV that does the initial planning and designing. Based on these cost estimates and revenue projections, Ofgem permits the interconnector and it can then be financed, build, maintained, and operated. However, the developer requests a license from the regulators in each country (Ofgem in UK and the respective National Regulatory Authority in the other country) for rights for a period of 25 years. The interconnector can auction capacity once it is operational and its technical availability conditions. No adjustment is made if the revenue is between the floor and cap. Revenue above the cap is returned to consumers and shortfall of revenue below the floor requires payment from consumers (a grid tariff), provided that a minimum efficiency threshold of 80% is met. In Norway, the cap is on return. It is technically not maximised but any real return over 8% is split between Statnett and the operator, where Statnett increasingly gets the largest share.

Prior to 2014, interconnectors were merchant assets whose income depends on auctioning capacity too but did not have a floor (for instance BritNed). Two merchant interconnectors have a cap (BritNed and ELEC). On a merchant basis, a private party or TSO who indirectly owns the assets can initiate the interconnector. In the case of BritNed, a UK-Dutch interconnector, the interconnector is private and realised with funding of the UK and Dutch TSOs National Grid and TenneT. Its ultimate beneficial owners are TSOs, but the SPV is indirectly owned and has independent governance. ELEC is an SPV owned by the Channel Tunnel, an example of a private initiative.

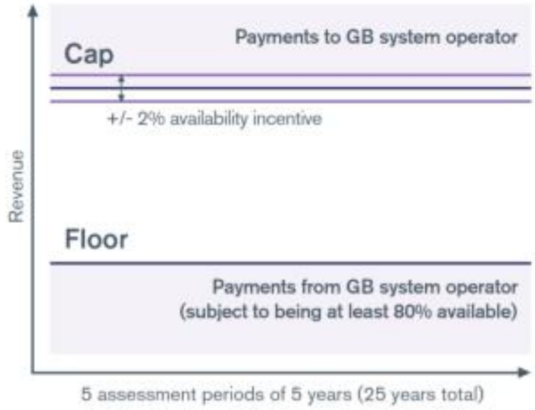


Figure 2-31. Cap-and-Floor

Countries with seemingly incompatible models (for instance a cap-and-floor vs. a TSO-led, or a TSO with a nonprofit regime versus a TSO with a revenue capped regime) solve this pragmatically. A project is split into two SPVs and each SPV is regulated by its own country of domicile. The arrangement is acceptable to the regulators. An example is Kriegers Flak, an interconnector between Denmark and Germany. Danish TSO Energinet owns 50% of the interconnector and operates under the Danish regime (nonprofit, recovering only cost and a sustainable return on equity) and 50Hertz, the German TSO owns the other 50% and operates under the German regime (capped revenue). It will connect Danish and German OWPs.

Even TSOs with seemingly contradicting regimes can connect. For Viking Link, the UK part of the JV is privately owned and is subject to the cap-and-floor system. The Danish part of the JV is regulated by Denmark and owned by the nonprofit Danish TSO Energinet. Viking Link is considered part of the Danish grid. Any income derived (revenue - cost) from the auctions goes towards lowering the tariff to Danish consumers.

2.3.2.3 Overview of ownership and revenue models of TSOs in NSEC countries.

Ownership of TSOs per NSEC country

TSOs are privately owned in Germany, Belgium, the UK, Luxemburg, and France (holding company is listed). All other NSEC country TSOs are owned by their respective governments, except for German and Luxembourg TSOs which have foreign ownership. While the ownership of the TSO is material, the regulatory framework that guides the revenue earning and return potential of the TSO is more relevant.

Belgium: Elia System Operator NV/SA is publicly listed and traded on Euronext Brussels. 44.96% is owned by Publi-T SCRL, a cooperative company of Belgian municipalities and intermunicipal companies, 51.81% is a free float and the remainder is owned by Publi-part, which is owned by a variety of state-owned and private companies.

Table 2-9 Overview of TSO ownership

Country	Revenue Model
Belgium	Private - Listed
Denmark	State owned. Not for profit
France	Private (Holding company listed)
Germany	Private
Ireland	State owned
Luxemburg	Private
The Netherlands	State owned
Norway	State owned
Sweden	State owned
UK	Private - Listed

Denmark: TSO Energinet is an independent public enterprise owned by the Danish state under the Ministry of Energy, Climate and Building.

France: Since 2005, RTE has been a public limited company, an autonomous subsidiary of EDF, which is a publicly listed electric utility company and is 83.6% owned by the French state. The Energy Regulatory Commission (CRE) directly oversees RTE's activities.

Germany: Germany has two TSOs that cover the German North Sea coast, TenneT TSO GmbH and 50Hertz. Both are structured as private companies. TenneT TSO GmbH is owned by the Dutch parent company TenneT Holding B.V. 50Hertz is part of the international Elia group, owned by the Belgian TSO. German state development bank KfW owns 20% and Elia owns 80%, the two shareholders set up a holding company under Belgian law Eurogrid International CVBA/SCRL that owns 50Herz.

Ireland: EirGrid Plc is a private company and fully owned by the Minister for Communications, Energy and Natural Resources.

Luxembourg: Creos is a merged entity of electricity and gas grid operators in the region. Luxembourg's TSO is 24.7% publicly owned (20% by the City of Luxembourg, 2.13% by Luxembourg municipal authorities, and 2.28% by the State of the Grand Duchy of Luxembourg). Its main private shareholder is Chinese-owned Encevo S.A. (75.43%). Luxembourg Institute of Regulation (ILR) organises and supervises network access and sets tariffs.

The Netherlands: TenneT consists of a Dutch and a German part, both are private companies, the Dutch company owns the German company and is a 100% owned by the Dutch state.

Norway: Statnett is a state enterprise owned by the Norwegian state through the Ministry of Petroleum and Energy.

Sweden: Svenska kraftnät is a state-owned public utility.

UK: In Great Britain, the main TSO is National Grid Electricity Transmission plc (NGET), which has a combined SO and TO role. National Grid is a publicly listed company traded at the London Stock Exchange and has a diversified shareholder base. It is owned by institutional investors such as CDPQ and asset managers such as BlackRock.

Revenue models of TSOs per NSEC country (non-profit, revenue capped, and private)

TSOs have a natural monopoly in all NSEC countries. The NRA regulates the TSO so returns generated by the TSO are capped. The most common method of regulating TSOs is the capped return method. It is used in all countries except the Netherlands.

In the UK, in addition to capping the revenue that TSOs generate, NRA has mechanisms in place for incentives and innovation by the TSO. This encourages TSOs to develop and implement new systems. Danish TSO Energinet's revenue is capped and it is a nonprofit, which are not allowed to build up equity or pay dividends to its owner. The Netherlands follows the weighted average cost of equity (WACC) approach for regulating the TSO TenneT, which is determined by Netherlands Authority for Consumers and Markets (ACM). Ofgem (UK) and BNetzA (Germany) also take WACC into consideration while regulating the TSO's revenues.

Table 2-10. Overview of TSO revenue models

Country	Revenue Model
Belgium	Revenue cap (Cost+ model)
Denmark	Cap on the return on the equity
France	Revenue cap
Germany	Revenue cap with WACC in consideration
Ireland	Revenue cap
Luxemburg	Revenue cap
The Netherlands	WACC
Norway	Revenue cap
Sweden	Revenue cap
UK	Revenue cap with WACC in consideration

Belgium: Elia is regulated under the Cost+ model by Commission for Regulation of Electricity and Gas (CREG). Under the Cost+ model, Elia can recover all costs associated with maintaining, operating, and expanding the grid, and servicing the debt in addition to that Elia is make profit as per the regulation. The profit represents the ROI for the equity holders.

Denmark: Energinet.dk is a state-owned, nonprofit enterprise, which is not allowed to build up equity or pay dividends to its owner, the Danish Ministry of Energy. It can include only the necessary costs of efficient operations plus the necessary return on the equity in its tariffs.

France: Commission de régulation de l'énergie (CRE) sets the grid tariffs in France, which means the Réseau de transport de l'électricité (RTE) can charge only on a fixed price, so its revenue is capped.

Germany: BNetzA the regulator sets standardised grid tariffs that are revised every 5 years, so the TSO's revenue is capped. If the TSO succeeds in lowering its costs below the permissible revenue during this period, the company can profit. WACC of the TSO is taken in consideration by BNetzA.

Ireland: Commission for Regulation of Utilities conducts a price review every 5 years, the grid tariffs/fee are standardised by this process. EirGrid's revenue is capped, it profits by lowering its cost.

Luxembourg: It follows a system similar to Ireland, where charges for using the grid are fixed by the regulator, so revenue is capped.

Netherlands: Netherlands ACM regulates TenneT under the WACC model. From consumers, TenneT is allowed to recover operating cost and cost of capital. TenneT can earn a return on capital invested in its regulatory asset base (RAB). WACC sets the regulatory return on the equity and debt compensation based on 50% equity and 50% debt split and is pre-tax rate. RAB is inflation indexed annually so the real WACC is used.

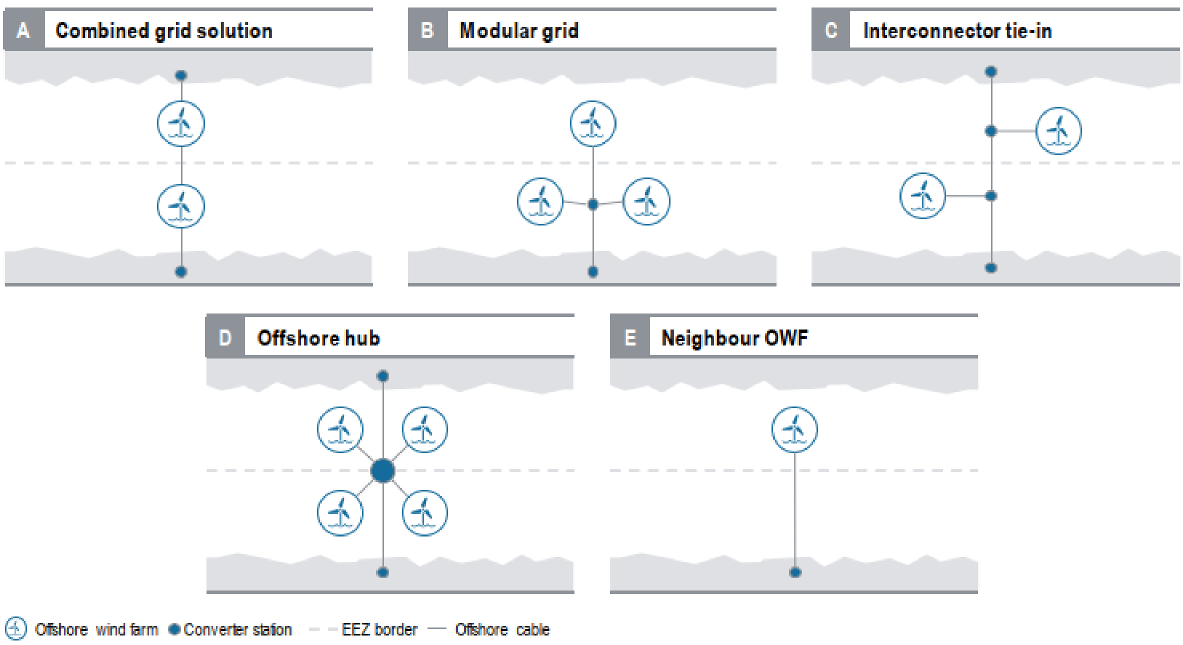
Norway: Revenues are determined and controlled by authorities through the Norwegian Water Resources and Energy Directorate (NVE) and an annual permitted revenue is stipulated. The intent is to set the permitted revenue at a level that allows Statnett (TSO) to cover the costs of grid development and maintenance, and provides a fair return on grid investments, assuming that the transmission grid is operated, utilised, and developed efficiently.

Sweden: The NRA for energy, the Swedish Energy Markets Inspectorate (Ei), determines a revenue cap for TSOs for a regulatory period of 4 years.

UK: Ofgem regulates TSOs under the RIIO model. RIIO is short for Revenue = Incentives + Innovation + Outputs. RIIO T1 is in force until March 2021. Ofgem includes WACC in the methodology. To encourage TSOs to provide additional benefits for consumers, Ofgem uses financial incentives that can either be penalties or additional revenue (funded by customers), depending on whether the TSO meets Ofgem's targets. As part of the RIIO framework, there are two funding mechanisms that encourage innovation across the energy industry. These funding mechanisms aim to help make the energy networks smarter, accelerate the development of a low carbon energy sector, and deliver financial benefits to consumers. The Network Innovation Allowance (NIA) provides an annual allowance to fund smaller scale projects. The Network Innovation Competition (NIC) is an annual competition to secure funding for large-scale demonstration projects aimed at building a lower carbon future. Under RIIO, the outputs that the TSO delivers are articulated and linked to the calculation of TSOs allowed revenue.

2.3.2.4 TSO positions regarding hybrid assets

In theory, five types of hybrid interconnector have been defined (Roland Berger, 2019).[195] We discuss how the OWP developers and interconnector developers can interact in each.



Combined grid solution (A): For a combined grid solution it is assumed that the interconnector directly connects the convertor station of the respective OWP. If a combined grid solution is

[195] Roland Berger, 2019. Hybrid projects: How to reduce costs and space of offshore developments. https://publications.europa.eu/portal2012-portlet/html/downloadHandler.jsp?identifier=59165f6d-802e-11e9-9f05-01aa75ed71a1&format=PDF&language=en&productionSystem=cellar

developed between countries where the TSO is responsible for the interconnector and connecting the OWP to the grid, then the TSO of the respective countries is responsible for the interconnectors on their side and will be regulated as per the regulations of the respective countries.

In Sweden, the OWP developer is responsible for connecting the OWP to the grid and the TSO is responsible for the interconnectors. If a combined grid solution interconnector is developed in Sweden, there is no mechanism to decide if the OWP developer or the TSO will be responsible for the hybrid interconnector. In the auction for the tariff for the OWP, the cost of the cable is included.

The UK follows an OFTO and a separate Ofgem regime for interconnectors. During the auction of the OWP, the Crown Estate in consultation with National Electricity Grid (SO) decides where the OWP will be connected to the grid. An OWP can be connected to an offshore interconnect. At the developer's election, the developer has the option to construct the cable connecting to the grid or the OFTO can. Generally, the OWP developer constructs the cable connecting to grid. Following the construction phase the cable is carved into separate entity. The carved-out entity owning the cable is auctioned out by Ofgem, the OWP developer is compensated from this auction. The winner of the auction is responsible for operating, maintaining, and decommissioning the cable, for which it receives a fee as per OFTO regime.

In a combined grid solution it is unclear how the OFTO regime for connecting the OWP to the grid and Ofgem regime for interconnectors will be applied. There is no cable so it is effectively a cost saving. However, as the cost of connecting the OWP with the interconnector, theoretically the OWP auction price can become lower.

An example of a combined grid solution is the FAB Link. FAB Link is a JV between RTE (French TSO) and a private developer; it will connect France to the UK via Alderney Island. It illustrates that a hybrid interconnector, where a TSO can function under a cap-and-floor regime. FAB Link will be used to transmit the tidal hydro electricity generated on Alderney Island; so it can be considered as a combined solution hybrid interconnector. The interconnector will be regulated under the cap-and-floor regime under both jurisdictions. The energy trader is agnostic (assuming no renewable energy constraints) as to where the electricity is generated. Electricity generated at Alderney Island can be transferred to the UK or the French side depending on demand.

Modular grid (B): Modular grids (multiple OWPs connected with an offshore converter but only connected to the domestic grid) are operational in many countries in some variations. In the countries where the TSO is responsible for connecting to the OWP, the whole grid is developed and operated by the TSO. In the Netherlands, the TSO sets up the offshore convertor station and the OWP developers develop the submarine cable and connect to the offshore convertor station (modular grid). All existing modular grids connect the national OWPs to their respective national grids. Currently, none of the modular grids connect to the OWP located in waters of another country.

In the Netherlands and Sweden, the developer is responsible for connecting the OWP, in the UK OFTO applies, and in all other countries the TSO is responsible. Connecting a foreign OWP only to a domestic grid indicates that its sole purpose is to export electricity to the host country with the modular grid. The foreign OWP will be auctioned and may even receive subsidies from the foreign country. This creates many questions as to how this foreign OWP will be regulated. Will the domestic or the foreign TSO or developer be responsible for connecting the OWP to the grid? In practice, this example does not yet exist. Possibly, an OWP in one country can connect to the modular grid of the other country if there are space efficiencies, in which case it is likely that the OWP may receive a tariff from the country hosting the modular grid, while the OWP may pay a land lease to the country on whose seabed it is built. Viking Link is an example of how cables and installation may traverse territory of different nations. Drawing the connecting cable will be regulated under the regime of the country hosting the modular grid. Again, this situation is hypothetical.

However, there are the possibilities for a foreign OWP to be connected to the grid but regulation in the respective countries remains unclear. When connecting the OWP to the grid (with exception of the Netherlands, Sweden, and the UK), the responsibility falls on the TSOs of the respective countries. It is unclear if the domestic or the foreign TSO will be responsible for connecting the OWP to the modular grid for further connection to the onshore grid. It is possible that the OWP developer will be responsible for connecting to the grid if the foreign OWP is located in the Netherlands or Sweden. In the UK, the OWP connections are regulated under OFTO. Until now OFTO has been applied only in UK waters.

Interconnector tie-in (C): In the interconnector tie-in model, convertor stations are placed on the interconnector and the OWP connects directly to these convertor stations. The rules of the respective countries will apply in cases of interconnector tie-in regimes. For countries where the TSO is responsible for the interconnector and for connecting the OWP, the TSO of that country is responsible for the whole grid on their side of the country.

In the Netherlands and Sweden, OWP developers will be responsible for connecting to the convertor station. In the UK, the OFTO regime can be used for connecting OWP to the convertor stations.

Offshore hub (D): In the offshore hub, multiple OWP (both domestic and foreign) connect to a single convertor station. For connecting an OWP to the convertor station, the responsibility is the same as that of interconnector tie-in. As the convertor station will deal with multiple OWP, a cost recover regime needs to be developed for charging the OWP for the convertor station. More clarity/guidelines are needed regarding who is responsible for the convertor station, the interconnector operator or the OWP operators or the TSOs. However, parties initiating offshore interconnectors have so far included onshore converters in their projects, establishing a precedent.

Neighbour OWP (E): Under this model, a foreign OWP is connected to the domestic grid. The sole purpose of this OWP is to export electricity. The OWP will be auctioned and regulated under the foreign countries' regulations. At present, the countries have regulations for connecting their OWP (domestic) to the grid. There is no clarity as how a neighbour OWP will be connected to the grid. However, the same arguments as under the modular grid may apply.

2.3.2.5 Cost recovery

As a hybrid interconnector has two components (the interconnector and the OWP connection) a cost recovery method needs to be developed. Such that a corresponding fee can be calculated that can be charged to individual OWP owners on the one hand and the revenue (congestion rent) generated by the interconnector capacity business on the other hand. Countries have different cost recovery models for OWP connections. The calculation is required to prevent cross-subsidisation of revenue between OWPs' tariff charges and interconnector congestion rents. The connection to Kriegers Flak is a combined grid solution interconnector linking the Danish and the German grid. It is jointly owned and operated by the TSOs of Denmark and Germany, which follow the regimes of the respective countries.

2.3.3 In-depth analyses of financing and cost recovery models of different investors

Most TSOs are government owned and are regulated to have a societal goal (delivering electricity at the lowest viable cost to consumers). Private, non-TSO infrastructure investors such as institutional investors and utilities have a profit optimisation goal. Institutional investors, such as pension funds, seek long-term inflation indexed stable cash flows with a predictable return to match their long-term pension obligations. They are more passive investors. Infrastructure private equity funds are more active investors than pension funds and typically have a shorter investment horizon. Their managers' goal is to realise the long-term objectives of their often pension fund clients, while seeking a rent and strong financial return to realise their profit share.

The mission of a TSO and private investors contrast. However, TSOs in NSEC countries seek efficiency and are allowed to make a regulated profit, with exception of the Danish TSO, which is a nonprofit and not allowed to pay its shareholder dividends. Effectively, TSOs have a maximum revenue they can earn and any savings they realise determines their profit. Some TSOs are fully government owned private companies and some are stock market listed companies, but by virtue of being regulated they have a social missioned framework within which profits can be made. Private investors like private equity infrastructure funds have been investing in regulated assets, particularly in the transport and utilities, for over 2 decades. They are familiar with the regulations and feel comfortable with regulated returns. Two private equity infrastructure funds publicly announced their investment into interconnectors, Namely Partners Group (in GreenLink) and Meridian Infrastructure Funds (in NeuConnect).

2.3.3.1 Equity providers

In most NSEC countries, TSOs fund interconnector projects through their available cash from operations after depreciation and issued debt. However, when a TSO's debt is not allowed to exceed a certain threshold (e.g. 60% in Germany) and additional capital is needed, then there are several options:

- Obtain grants from the EU
- Strengthen the balance sheet of the TSO (with government capital)
- Increase the cost reimbursement of the TSO (increase the regulated revenue or return on equity, which the public pays through tariffs)
- Raise external capital from private equity

With the increasing demand for grid expansion, TSO balance sheets may become constrained. In the UK, the chosen model for funding interconnectors is public private partnerships with a government guarantee (cap-and-floor system). Another example of drawing in private capital is the JV between TenneT TSO GmbH and infrastructure private equity fund Copenhagen Infrastructure Partners for four offshore connectors (not an interconnector) that are part of the German grid. This was an exceptional situation: TenneT's balance sheet could not keep up with the investment pace required for grid expansion (particularly for connecting OWP) that the TSO was to exclusively fund so the Dutch and German regulators made an exception for the JV.

For interconnectors linked to the UK, the counterparty risk effectively is the UK government (investment grade credit rating, -AA), which guarantees a minimum revenue. This mitigates risk sufficiently to make these assets attractive to independent private investors and financiers, especially in a low interest environment. Interconnectors linking with other countries than the UK do not provide a guaranteed floor. Revenue has full volume and price risk. These interconnectors are a natural monopoly and provide an essential service; they have relatively stable revenue streams with a low churn rate. TSOs are set up to take on this risk and fund SPVs holding the interconnectors from their balance sheets.

Private equity providers can be divided into three groups: developers, direct investing institutional investors (such as pension funds and sovereign wealth funds), and infrastructure private equity funds. A developer can be a private independent developer, a TSO, or a consortium of utilities (project North Connect).

There is an abundance of capital seeking infrastructure investments and as pension funds increase their allocation to infrastructure, dry powder has jumped past USD 200 billion in the first half of 2019.[196] With more equity than assets available, competition is high and investors are willing to pay more for quality assets, especially in a low interest rate environment. As a result, to obtain assets, investors look to enter sooner and are willing to take on more development and construction risk. While this bodes well for the private funding of interconnector assets, interconnectors are very capital intensive. The average infrastructure transaction size was US$149 million (Q3 2016-Q2 2019), whereas an offshore interconnector in the North Sea costs between €0.4 billion to €2 billion to design and build (depending on the distance to shore and depth of the sea). At an equity share of 50%-60%

[196] Preqin, 2019. Quarterly Update: Infrastructure Q2 2019. https://docs.preqin.com/quarterly/inf/Preqin-Quarterly-Update-Infrastructure-Q2-2019.pdf

the equity contribution per interconnector ranges between €0.2 billion to €1.0 billion. By comparison, that is 1.3 times to 6.7 times the average infrastructure investment and can only be accomplished by the largest of private infrastructure investors, such as Brookfield, GIP, Macquarie Super Core Infrastructure Fund, Partners Group, and direct investing pension funds and sovereign wealth funds.

Typically, an interconnector can run for 40 years (for example, transformers may thereafter be outdated). But private interconnector concessions tend to have a duration of 25 years, which effectively is the maximum project investment horizon. In Norway, a private interconnector transfers to the TSO after 25 years, as the cash flows would offset the higher average cost of electricity prices that the TSO or the public may incur in the first 25 years. Interconnectors are considered a core (low) infrastructure risk and offer a gross equity return of 7%-8%.

Developers

A developer of an interconnector can be the TSO or a private independent developer, the latter is often the initiator of an OWP or can be a utility (NorthConnect). Currently, only UK-linked projects can have a private independent developer. Typically, when an independent private developer completes the design and certain studies and permitting, which may take 6 to 10 years, an institutional investor will join such as a pension fund or an infrastructure private equity fund. In the case of NorthConnect, the developers took 9 years to bring the project to a permitting decision at the Norwegian government (which did not proceed). With construction, the investment horizon of a developer can easily be 10 years and is the riskiest part of the project.

Element Power, an independent offshore wind developer, realised the Irish-UK merchant interconnector Greenlink. Once the project was sufficiently developed, an infrastructure private equity fund, Partners Group, joined the consortium to realise further permitting, construction, and operation. Typically, an institutional investor pays the developer's margin as part of the CAPEX and the developer may retain a portion of the project's equity. Together, this provides income and upside to the developer, which is the business model of a private independent developer. Payoff to a utility that develops an interconnector occurs when it is operational.

Hudson Sustainable Investments, invested through its private equity fund in Element Power, whom jointly supported the development of Greenlink. Non-utility private, independent developers seek an ROI exceeding an invested capital. The transactions are private; however, we expect that returns in terms of IRR to be in the range of 15%-20% IRR.

Institutional investors

Direct investing pension funds and some sovereign wealth funds (SWFs) are relatively passive infrastructure investors. They provide long-term equity and seek out assets with long-term cash flows that match their long-term pension or national obligations. Examples of direct investing pension funds and SWFs include APG, PGGM, OTTP, CDPQ, the Australian supers, and government funds from Asia and the Middle East. They seek a return on equity equal to return of the project and typically will hold the project until maturity. These investors aim for investments of €100 million and up. They are the largest of equity providers that can afford front office teams that seek out, invest, and administrate investments.

Mid-sized and smaller pension funds do not have that capacity and invest either through pools setup by the asset managers of the largest equity providers or they participate through infrastructure private equity funds. There are two types of infrastructure private equity funds, open-ended vehicles and closed-end funds. These funds act as distribution channels to pension funds. As fund managers charge a management fee and a profit share, the required return of equity of infrastructure funds is higher than that of direct investing pension funds.

Open-ended infrastructure private equity funds, like direct investing pension funds, do not have a fixed investment horizon and hold assets to maturity (through the concession period). Closed-ended funds typically have a fund duration of 10 to 15 years. Effectively, the holding period of a closed-end fund is 5 to 10 years. Closed-end funds create value by optimising operational efficiency and the financing of the asset. These funds realise value by aggregating smaller assets, which (when combined) may offer economies of scale that fit the investment demand size of long-term investors. Open-ended funds are more focused on long-term cash flows. Closed-end funds seek a cash yield and some capital gain, which fund managers achieve by selling the projected cash flows of the remaining concession period at a premium to longer-term investors that seek a lower but de-risked return resulting from mostly stabilised dividends. Once the asset provides stabilised cash flows, a closed-end fund manager sells the investment at a premium, realising a net return to investors of about 8%-9% gross. Buyers of the de-risked asset are direct investing pension funds and open-ended vehicles that seek stable long-term contacted infrastructure and accept a lower return.

Open-ended funds charge their investor lower management fees and profit shares than closed-end fund managers and have lower return expectations, around a net yield 6%-8%.Typically, large infrastructure private equity funds such as IFM and Macquarie's MSCIF seek similar sized commitments as direct investing pension funds and SFWs (greater than €100 million).

Core and Core+ infrastructure funds tend to buy brownfield projects (operational projects). Value add and opportunistic funds can take on construction risk. Opportunistic funds may accept licensing and other development risks and have a similar business model to private independent developers.

Table 2-11. Investor horizon and required IRR

Investors of core assets	Investment horizon	Required Gross IRR
Institutional investor	Term of project	6%-7%
Open-ended funds	Term of project	6%-8%[197]
Close-ended funds (core-core+)	10-15 Years	7%-9%

Utilities

Utilities are strategic (industry) investors that are primarily profit driven and seek out investments if it complements their strategic goals. They act as a developer, and are vertically integrated by investing in an interconnector. Utilities are power brokers and use and may invest an interconnector to arbitrage the spot or futures market price of electricity between two or more countries. They hold the project to maturity and typically have a lower cost of capital than infrastructure private equity funds and (from that perspective) are a natural partner for private independent initiatives that link to the UK.

Currently, there is one consortium of utilities that has initiated an interconnector, NorthConnect. It is a 1,400 MW DC 665 km long power cable between Norway and the UK, sufficient to supply 25% of the Scottish peak demand. Expected cost is between €1.7-€2.0 billion (£1.75 billion) and it is subject to the UK's cap-and-floor regime. NorthConnect, is owned by Vattenfall and three municipal-owned power companies (E-CO Energi, Agder Energi, and Lyse Produksjon), who fund the project. Indirectly, the Norwegian and Swedish states have ownership interests in these initiators via Agder Energi (Statkraft) and Vattenfall. It received an €10 million grant from CEF.[198] NorthConnect is founded to sell relatively inexpensive Norwegian hydro-generated electricity to Scotland where electricity is more expensive. Particularly when Scottish OWPs produce insufficient electricity to meet demand. Conversely, it allows for storage of excess Scottish wind generated electricity in Norwegian hydro storage facilities.

Swedish Vattenfall's main markets are Denmark, Germany, The Netherlands, Sweden, and the UK; it does not have Norwegian operations currently. NorthConnect seeks to increase interconnection capacity to improve market efficiency. Effectively, the consortium seeks to preserve the value of and get paid for hydropower in the future energy market.[199] Norwegian partners are generators of hydroelectricity; Vattenval and the Norwegian partners trade electricity. They participate in the project

[197] Infrastructure Investor, 2020. Infra Debt 'still in ramp up phase'. https://www.infrastructureinvestor.com/infra-debt-still-in-ramp-up-phase/

[198] reNews, 2017. UK-Norway link bags EU grant. https://renews.biz/106040/northconnect-scores-eu-cash/

[199] NorthConnect, 2020. FAQ. https://northconnect.co.uk/faq

and believes the investment will be accretive, meaning it will realise a return higher than their corporate WACCs.

Effectively, NorthConnect competes with two interconnectors in the 2014 approved TSO-led interconnector initiatives: Nord.Link (NO-DE) and North Sea Network (NO-UK). These two projects add 1,400 MW of capacity each, an increase of 50% of Norway's interconnection capacity. Additional capacity from NorthConnect reduces congestion income to all the interconnectors and increases the average price of electricity in Norway by adding more expensive Scottish electricity to otherwise less expensive Norwegian electricity. It benefits utilities at the expense of Norwegian consumers.

If built, the short-term gains of NorthConnect are allocated to the utilities (with public and private owners) and long-term gains can be had by the Norwegian state when the interconnect is transferred after 25 years. These gains depend on how much of the short-term resulting windfalls goes to the Norwegian treasury (shareholder in the Norwegian utilities), how much goes to Swedish Vattenfall, and how much goes to private shareholders in the publicly traded utilities. They also depend on what the Norwegian treasury does with the gain—does it go towards the TSO's budget, thereby reducing the tariffs to the Norwegian public? Eventually, it depends on whether a TSO or a utility can build and operate an interconnector more efficiently. On 25 March 2020, the Ministry of Petroleum and Energy in Norway determined that it does not have sufficient insight as to what the impact of NorthConnect will be to process the license application.[200] The project appears to be on hold.

TSOs

A TSO's equity return requirement is determined by its mix of the by national regulator permitted return on equity, cost of debt, and corporate tax-shield, or a WACC. NSEC TSOs investing in interconnectors typically provide funding on a corporate financing basis.

Under corporate finance, the TSO funds the interconnector project from their balance sheet. A TSO attracts debt through the holding and then funds the project. Debt used for the project is covered and serviced by the entire portfolio of the TSO. The risk associated with the project is spread out across whole TSO and debt providers effectively take on the risk of the TSO versus the project.

Under project financing, the SPV, which holds interconnector, attracts debt and its shareholders provide equity. Debt will be paid from the cashflows generated by the SPV, which increases the perceived risk (unless the shareholders agreed to a parent guarantee). Due to higher perceived risk of project financing, debt providers will demand a higher required coupon, governance, and assurances compared to corporate financing.

A TSO can attract inexpensive financing from EIB and the bond market for long-term financing, commercial loans for short-term financing, equity contributions from the state or shareholders if publicly traded, EU grants, and the TSO can reinvest the generated cash flows from operations.

The ownership form, the relation of debt to equity (leverage/gearing) on their balance sheet, and the credit ratings are some of the factors that affect TSOs' financial strategies, mainly their ability to raise debt and equity to meet the investment needs.

Elia and National Transmission Grid are listed companies, they can raise additional equity by issuing new shares. Électricité de France is the parent company of Réseau de Transport d'Électricité (RTE) and is listed on the Paris stock exchange. Raising external capital may be restricted due to country laws applicable to the TSO. For example, by Dutch law, TenneT has to be owned by the Dutch government. TenneT can only raise new equity from the Dutch state.

[200] Ministry of Petroleum and Energy (Netherlands), 2020. Press Release: Insufficient grounds to decide on the application for the NorthConnect project. https://www.regjeringen.no/en/aktuelt/insufficient-grounds-to-decide-on-the-application-for-the-northconnect-project/id2694855/

EU Framework for Investment

In addition to traditional sources of capital, the electricity infrastructure projects in Europe are also eligible grants from EC. PCIs aim to aid the completion of an integrated European energy market while complying with energy policy objectives for affordable, secure, and sustainable energy. PCIs are governed under Regulation (EU) No 347/2013 on guidelines for trans-European energy networks (TEN-E). The main benefits of the PCI label are:

- Accelerated planning and permitting procedures (3.5 years for granting a permit)
- A single national authority for providing permits (one-stop-shop)
- Streamlining of environmental assessment procedures
- Increased public participation through consultations
- Increased visibility to investors
- Access to financial support by the Connecting Europe Facility

Qualified electricity infrastructure projects are eligible for below programs for financing

- Cohesion Fund
- Connecting Europe Facility
- Horizon 2020 and Horizon Europe
- European Regional Development Fund
- European Investment Bank
- European Fund for Strategic Investments
- European Energy Programme for Recovery

2.3.3.2 Financing

Private interconnectors are financed on a non-resource project financing basis. In project financing the asset is financed based on the asset's risks and the SPV holding the interconnector borrows and its shareholders provide equity funding. However, interconnectors set up by a TSO are often directly funded from a TSO's balance sheet through corporate financing. Meaning that the TSO issues bonds and the risk of the loan is based on the corporate risk of the borrower rather than of an asset.

Debt providers include international financing institutions (IFIs), which effectively implies the EIB for the current NSEC countries, banks, insurance companies and infrastructure debt funds. As well as the bond market.

IFIs

IFI's provide long tenors (15-20 years) at more attractive rates than commercial banks and are popular with TSOs and private investors. The EIB can draw from the European Fund for Strategic Investments. In total, EIB tends to fund 50% of the capital requirements of TSOs. For instance, the EIB provided a €100 million hybrid loan in 2017 for the development of NordLink, an interconnector between Germany and Norway.

Commercial banks

Bank financing makes up 80%-90% of total financing in the total infrastructure market, according to the 2020 infrastructure finance outlook by UBS Asset Management Real Estate & Private Markets

(REPM).[201] In Europe, 70%-80% of infrastructure financing has historically been provided by the banking sector with only around 20%-30% from capital markets, according to Schroders.[202]

Commercial banks are more expensive than IFIs and are regulated through Basel III, which limits the tenor of the loan to a maximum 15 years; banks typically lend for 5 to 10 years. The term of interconnectors is much longer (20 to 40 years), which introduces a refinancing risk. In practice, banks can structure around this. However, there are other lenders that fill the gap. Insurers and private infrastructure debt funds are not limited by Basel III regulation and provide long-term financing. Although small compared with the €118 billion European private infrastructure debt market, the infrastructure debt fund market is growing in Europe. Between 2017 and 2019, 19 senior debt strategies were launched, raising €5.4 billion.

Bonds

An interconnector asset also can be financed through a bond issue. TSOs often issue a variety of corporate bonds, which can have a maturity of 10 to 20 years. The green bond issues by TenneT are one example, they finance projects with an environment purpose. In Europe, the 2019 Greenbond issue was US$117 billion.[203] Average oversubscription was 2.8 times for green bonds and 2.0 times for vanilla equivalents. Spread compression averaged 13.3 bps for green bonds and 12.9 bps for vanilla bonds.[204] Greenbond issued by investment grade TSOs, such as TenneT, are in demand. They effectively provide a higher return than government bonds but are ultimately guaranteed by a state. There is the increasing demand for green financial products. Approximately 50% of green bonds issued are purchased by impact investors.

2.3.4 Lessons learned

Through the development of interconnectors, lessons learned have been realised on several fronts. While parties have pragmatically solved barriers, coordination is key. Most gain is on the permitting and planning side. However, there are precedents regarding matters that were previously considered unknowns and risks. These include uncertainly regarding legislating cross-border cables, regimes for revenue, planning OFWs and interconnector capacity (competition), transferring renewable electricity across borders and national green targets, and the impact on funding.

During an interview, an investor in a UK linked interconnector commented that technology and construction risk (or lack thereof) of interconnectors are well known and do not form a barrier, which makes project financing more straightforward. For instance, the grids of Denmark and Germany operate at different frequencies. This has successfully been overcome as demonstrated by hybrid interconnector project Kriegers Flak. A difference between grid codes in two or more countries on an interconnector no longer constitute a timing risk or a technical challenge, they are known. While still capital intensive, the cost of interconnectors is decreasing, which decreases the cost barrier.

There is uncertainty around the responsibility and rules to provide access to maritime space for offshore wind farms (location selection, site pre-investigation, and tender execution). For instance, TenneT had financial difficulty when several OWPs were developed and needed a connection to the grid. As a result, TenneT could not muster the financial resources in the short-term and joined a JV with a private party to realise the connections. There is a need for coordinated centralised planning,

[201] IPE Real Assets, 2020. Infrastructure debt funds come of age. https://realassets.ipe.com/infrastructure/infrastructure-debt-funds-come-of-age/10043408.article
[202] Schroders, 2017. Infrastructure financing – an overview. https://www.schroders.com/en/sysglobalassets/digital/hongkong/institutional/201704_infrastructure_financing_an_overview.pdf
[203] Climate Bonds Initiative, 2020. 2019 Green Bond Market Summary. https://www.climatebonds.net/files/reports/2019_annual_highlights-final.pdf
[204] Climate Bonds Initiative, 2019. Green Bond Pricing in the Primary Market.: July-December 2019. https://www.climatebonds.net/files/reports/climate-bonds-pricing-report-h2-2019-310320-final.pdf

this equally applies to the planning of new hybrid interconnectors, which is now defined by government bodies doing maritime planning and auction schedules for OWPs in those areas.

During the interview, the previously mentioned investor commented that permitting is time intensive and complex, and it is still the most important hurdle. Multilateral and supranational coordination by the EU is desired.

Another lesson learned lies in the failure of developers to align planning across assets and countries. While there is national planning, further planning and coordination in the North Sea area is helpful. It makes sense to plan the OWP and the interconnector in parallel, which requires a coordinated approach among the countries' NRAs.

Investors perceive that there may be uncertainty about regulation from jurisdictions over cross-border cable systems. However, hybrid interconnector Kriegers Flak (TSO-led), interconnector Neu Connect (fully private, Meridian, and Allianz), and interconnector Viking Link (TSO-led but under the Ofgem regime for the UK side) show how cables that traverse multiple countries can be legislated successfully. Nue Connector connects Germany and the UK and passes through the Netherlands.

Cross-border cables at first glance may have regulatory conflict—under which regime is revenue realised? TSOs with seemingly incompatible regimes have overcome this barrier by structuring the interconnector via joint ownership and operations agreements and separate SPVs where each country owns its side of the project (for example, 50%-50%). Each SPV is regulated under its home country. OWPs connecting to these interconnectors can be regulated nationally, as can the responsibility for the realisation and connecting of submarine cables to the OWPs. To attract private investors, the UK introduced the cap-and-floor methodology in 2014, which provides clarity and regulation to private parties on this matter in the UK. Ireland followed suit, as well. Some TSOs were willing to adopt the UK's cap-and-floor system for specific interconnectors linking with the UK or Ireland. With respect to hybrid interconnectors, OWPs are regulated by the countries in whose territory they are built.

Looking forward, planning and coordination of new (hybrid) interconnector capacity additions in the NSEC area will be increasingly important; particularly when electricity prices converge and private initiatives are added. This is especially the case as private initiatives enter the fray alongside already planned and permitted TSO-led projects in markets that were traditionally TSO dominated. NorthConnect in Norway, which was initiated in 2011, is one such example. In 2016, the Norwegian government ruled that private parties were not allowed to initiate interconnects and in 2019 ruled that they were allowed, to then decide in 2020 that the effects of adding capacity are insufficiently known to permit the private addition. In hindsight, the parties involved could have explored upfront the practical issues of adding capacity, the resulting competition between private and TSO-led interconnectors, and the cost to a country. Political considerations such as the need for greening—a philosophy about who earns the gain and carries the costs of higher average electricity prices and public versus private ownership—make those decisions more difficult. But the economic outcomes of these scenarios can be gauged upfront, which can help the decision-making process, risk assessment, and the allocation of resources by the government and the private parties that look to develop new interconnectors in a country.

Financial return and the project horizon do not constrain the realisation of hybrid interconnectors, they are favourable to infrastructure investors. See section 2.3.3.1, which explains the roles of different equity providers. While it takes 5 to 10 years to realise permitting, including construction permits and EIAs, it is the developer's responsibility to take on that risk. Returns are proportionally rewarding. A developer advances the project in anticipation of a pension fund or infrastructure private equity fund joining when the project is sufficiently de-risked. Under the cap-and-floor model, the debt service and OPEX of the (hybrid) interconnector owned by the private investor, independent developer, or TSO is guaranteed through a floor. Any gain is realised up to the cap, which effectively is a 25-year availability-based PPP that allows for a project return potential of 6%-7%. This is a good project return for a core infrastructure asset and investors are accustomed to such a potential. Investors and developers can negotiate the calculation of OPEX, revenue, and funding with Ofgem. From an investor's point of view, this leaves room to optimise the project.

Developers typically charge the joining equity provider rent, offsetting the development risk. Interconnectors with independent investors and TSOs have successfully permitted (hybrid) interconnector projects. Under any other model, the TSO is responsible for realising the interconnector and receives revenue from auctions. As the interconnector providers a 40-year long-term stable cash flow, it is financeable and provides a steady income to the TSO. An interconnector is a monopoly (or oligopoly when competing capacity is added to the same markets) that provides an essential service, as such the risk is low.

3. Task 2 – Analysis of and recommendations on an integrated framework for the financing of joint (hybrid) OWP

Task 2 (section 3) provides analysis of and recommendations on an integrated framework for the financing of joint (hybrid) OWP. The recommendations are developed with a view to NSEC countries and their cooperation, but are also largely applicable to other offshore regions, such as the Baltic or Mediterranean seas. Section 3.1 discusses approaches to cooperation and support scheme design. Section 3.2 addresses one of the key barriers to the realisation of hybrid offshore projects: the proper analysis and subsequent reallocation of costs and benefits resulting from hybrid offshore projects. Section 3.3 develops recommendations on the use of CEF and the Renewables Financing Mechanism for hybrid offshore projects. Section 3.4 presents illustrative timelines for different hybrid configurations for offshore wind solutions.

3.1 Approaches to cooperation and support scheme design for joint (hybrid) OWPs

This section includes recommendations on an integrated framework for the financing of hybrid assets, including the impact of market arrangements on hybrid projects, the cooperation software, the basic structure of (joint) hybrid offshore projects, the support scheme design, and the option to include PtX solutions in the project setup.

3.1.1 Impact of different market arrangements on the financing of hybrid OWPs

The market arrangement defines how offshore wind farms are allocated to specific bidding zones and how interconnection capacity between these bidding zones is allocated. Various stakeholders are directly affected by the market arrangement, including TSOs, offshore wind farm developers (and operators), regulatory agencies, consumers, and those financing support schemes (taxpayers/levy payers). The market arrangement has a significant impact on the financing of hybrid offshore projects. Hence, this section includes related high level considerations around the issue.[205] Two options are discussed: the HZ and OBZ arrangement. They are accounted for as boundary conditions for the assessment of different support scheme design options and for the CBCA. The key impact that market arrangements have on the financing of hybrid offshore wind farms is on the revenues for project operators and for TSOs, which decrease in the former case and increase in the latter case.

The HZ setup indicates that hybrid OWPs bid into the existing bidding zones of their respective exclusive economic zone. In this setup, the offshore wind farms receive the electricity price of their home market and are also able to operate as a Balance Responsible Party within that bidding zone. There are several challenges to this setup related to compliance with the Electricity Market Regulation (EMR)[206] and the Electricity Market Directive (EMD),[207] as well as efficiency considerations.

Article 16, 8b of the EMR recast states that at least 70% of the physical capacity of each interconnector must be offered to market participants for the purpose of hosting cross-border trade. However, the OWP capacity would likely exceed the 30% remaining capacity (unless the interconnector is over-dimensioned). First, the OWP would have to be curtailed whenever cross-border trade is expected to make use of the cross-border capacity to ensure the 70% are offered to market participants, leading to significant curtailment of the OWP. To allow the hybrid OWP (with

[205] See the project ENER/B1/2019-560 – " Recommendations for market arrangements for offshore hybrid assets in the North Sea "- Framework contract MOVE/ENER/SRD/2016-498 – Lot 2, for an in-depth analysis of this issue.

[206] Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity.

[207] Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity.

close to zero operational costs) to feed its electricity into the interconnector, it would receive a sort of priority access over cross-border trade by being included in the HZ. The connection from the OWP to the HZ would then be considered an internal line and not an interconnector. This in turn would breach the 70% rule and would make a change of Article 16 necessary, for instance, by providing a case-by-case derogation approach. Such a derogation approach would imply uncertainty for investments in hybrid OWPs. Alternatively, a permanent exemption would have to be introduced to Article 16.[208]

Article 12 of the EMR states that dispatch shall be market based. Providing priority access for the hybrid OWP over cross-border trade by extending the HZ to the OWP and defining the connection to shore as an internal line instead of an interconnector could be seen as incompatible with Article 12. However, one may argue that, once an exemption is granted for the 70% rule, the dispatch of the OWP is market based as it is dispatched according to prices in the HZ.

Other legal concerns relate to Article 3 of the EMD (Member State shall not hamper cross-border trade) and Article 6 of the EMD (non-discriminatory grid access) which would also have to be assessed in more detail to check compliance with the HZ setup.

Apart from legal concerns and potentially required changes, there is a concern that the HZ solution may result in less-than optimal grid operation:

- Priority access for hybrid OWPs may lead to inefficient use of interconnection capacity. In certain situations, welfare may be maximised using the interconnector capacity for trade between the two bidding zones instead of using it for the infeed of the OWP.

- Congestion management is required to reduce capacity restrictions between the home market and the OWP may be economically less efficient than in the OBZ solution (in which flow-based market coupling ensures maximised welfare).

- Wind forecast errors impact the available amount of cross-border interconnection capacity: in the HZ setup, wind forecasting of the hybrid OWP is required to determine available cross-border interconnection capacity. The TSO needs to calculate the available capacity based on the wind forecast 2 days in advance, whereas the energy producer can correct its forecast on shorter timeframes. As a result, the TSO is dependent on its own wind forecast, which would effectively shift forecasting responsibilities between TSOs and OWP operators.

- Even though market participants are fully financially responsible for their imbalances, they are not incentivised to solve imbalances on the location of the OWP but anywhere in the bidding zone. This can lead to congestion problems on the transmission infrastructure between the OWP and the home market.

The OBZ was proposed to address these challenges. In the OBZ wind farms bid into a newly created offshore bidding zone that reflects the structural congestion in the grid (the connections to shore). As a result, in an OBZ, all trade is considered to be cross-border and hence the 70% are seen as being available to the market (i.e. compliant with Article 16 of the EMR). Article 12 of the EMR and Article 3 of the EMD would be applicable without changes. Apart from this advantage, the OBZ would provide transparency on the value of transmission capacities, as those would be reflected in the congestion rents. Moreover, the physical reality of the grid and OWP and interconnection flows are co-optimised by the flow-based market coupling algorithm, which may result in more efficient dispatch of units compared to the HZ.

Despite these advantages, there are several challenges related to the OBZ solution that would have to be solved when implementing them. First, there are several issues related to the governance of OBZs, each of which require substantial legal changes on national level:

[208] This approach would in turn have to be checked in terms of its compliance with the free movement of goods articles (26 and 28-37) of the Treaty on the Functioning of the European Union (TFEU).

- Traditional bidding zones (and the HZ solution) are typically operated within nation state boundaries. For an OBZ that likely spans two or more EEZs, a competent regulatory authority and a responsible system operator have to be defined.[209] These would also have to be responsible for effectively ensuring that the 70% rule is respected, so joint legal responsibilities would arise.

- Entities must be defined that are in charge for the regulatory approval and enforcement of market rules (e.g. regarding imbalance settlement and grid connections) for the OBZ.

- Establishing an OBZ may require a broader bidding zone review, inducing significant transaction costs and impacts on many other market participants and existing generation assets.

Issues arising from OBZ for the financing of hybrid OWPs and the support scheme design relate to lower revenues and potentially higher revenue uncertainty for project developers and operators:

- The OBZ will usually result in the lowest price of all adjacent bidding zones because congestion will be on the side with higher prices. As a result, revenues for offshore operators structurally decrease in the OBZ compared to the HZ solution.

- Revenue risks may potentially increase because project developers and operators have to anticipate/forecast the prices of all adjacent bidding zones and not just the HZ. This is particularly relevant in a context of fully merchant OWPs (projects without support payments) as those are fully exposed to the market price risk.[210]

- The revenue risk may increase even more significantly because of negative prices: The OBZ will converge with negative prices in any of the adjacent bidding zones and thus would experience more negative prices than each of the single bidding zones. Negative prices result in self-curtailment of the OWP and related income losses.

The quantitative extent to which lower and negative prices in the OBZ worsen the overall revenue situation of an OWP depends on various factors, including the exact grid topology and the existing and expected market price levels in the adjacent bidding zones. On a conceptual level, the OBZ results in a more efficient dispatch than the HZ solution whenever it reflects negative prices in one adjacent bidding zone. The more the OBZ increases efficiency, the more negative prices effectively impact the business case of OWP. One effect on the system level of OBZs and the increased role of negative prices is that offshore wind capacities would be curtailed before conventional capacities, which are technically and financially more inert than OWPs.

Various solutions are discussed to compensate the structurally lower revenues in the OBZ compared to the HZ solution: Transferring congestion rents from TSOs to the operators either via financial transmission rights (FTRs), transferring auction revenues (ARRs), or via the support scheme design. If OWPs were awarded FTRs for free from the TSOs, they could get revenues from price differences between their home market and an interconnected market when selling the FTRs. This may exactly offset the revenue loss an OWP experience because of being in an OBZ. How many FTRs are to be handed out to which OWPs within an OBZ has to be determined carefully. An additional challenge with this solution is that the EMR defines (in Article 19) that congestion income may be used for interconnector reinforcement or to lower grid tariffs. It does not include an option to compensate generation asset operators for income losses due to a certain market arrangement. Adding this option to the use of congestion rents would in principle put into question the definite use of congestion rents for infrastructure, possibly with repercussions beyond hybrid OWPs. In addition, the implementation,

[209] OBZ may also be set up within national boundaries, but for many hybrid OWP setups, this does not seem likely / practical.

[210] It is important to note that the zero-bids were realised without a hybrid component and thus in a market arrangement equal to the home zone solution discussed here. Thus, these investors are expecting structurally higher market revenues and less revenue uncertainty compared to an OWP in an OBZ.

use, and trade of FTRs is related to transaction costs, including financial rules under the Basel III measures developed by the Basel Committee on Banking Supervision.

As an alternative, OWPs could receive a certain share of ARR from the TSOs sale of FTRs at the interconnector. OWPs would not have to deal with the FTRs themselves. However, in this case, OWPs would not receive a full hedge against price differences because the value of ARR would depend on market participants expectations rather than on actual price differences between bidding zones. Again, transferring congestion income from TSOs to OWPs would require changes in Article 19 of the EMR.

If the FTR and ARR solutions are not deemed feasible, the support scheme may have to offset the lower revenues in an OBZ (see section 3.1.4.3). In an OBZ, the need for support payments is more likely than in an HZ solution and the amount of required support will increase. Both an (asymmetric/one-sided) sliding feed-in premium or a (symmetric/double-sided) CfD may be suitable in this context to address lower market price levels. However, a support scheme will not be able to offset the effects of negative prices, as support is generally deemed to distort markets if paid during negative prices. Hence, the State Aid Guidelines for Energy and Environmental Protection determine in Article 124 that support schemes need to put measures in place “to ensure that generators have no incentive to generate electricity under negative prices.”[211] In practice, for OWPs in OBZ developers are likely to include the risk of revenue losses due to negative prices in their bid in support schemes (i.e. to be compensated during times of positive prices). This risk is nonproductive and increases the cost of capital for OWPs.

The HZ and OBZ solutions both require substantial legal changes on the EU and national level to be implemented. From the perspective of financing hybrid OWPs, the key aspects are structurally lower revenues and potentially higher revenue risks in OBZ compared to an HZ solution. Even if support schemes offset the structurally lower incomes, the increased risk of negative prices persists.

3.1.2 The cooperation software

The cooperation software defines the cooperation setup apart from the chosen technical project configuration (i.e. hardware). The following design elements need to be determined:

- Cooperation mechanism
- Support scheme
- Financing of support
- Transfer of RES statistics

Cooperation mechanism

The cooperation mechanisms defined in the Directive (EU) 2018/2001(RED II) are available to establish cooperation between Member States on financing RES generation assets and RES target achievement. They include the following options:

Article 8 Statistical transfers between Member States: Member States may agree on the statistical transfer of a specified amount of energy from renewable sources from one Member State to another based on an agreed transfer price (e.g. Luxembourg purchasing RES statistics from an offshore park in of the other NSEC countries). Statistical transfers are unlikely related to specific projects nor do they have to be related to new projects (i.e. can be existing ones), although the details of such an agreement can be fully defined by the involved Member States.

Article 9 Joint projects between Member States: Member States may implement joint projects, i.e. new projects, and subsequently share the costs and benefits of such a project (i.e. agree on the share of RES statistics to be transferred from one Member State to the other). There might be multi-project

[211] Guidelines on State aid for environmental protection and energy 2014-2020.

arrangements and single-project arrangements. A likely case is to use this cooperation mechanism for single cooperation projects.

Article 11 Joint projects between Member States and third countries: Member States may also implement projects (including the distribution of costs and benefits) with third countries. However, such projects can only relate to the electricity sector, as a physical link needs to be established with that third country and interconnector capacity needs to be booked to ensure an infeed of electricity into the EU electricity system. To the extent that a hybrid offshore asset includes a third country, cooperation under this model may be feasible. This option may become relevant in the context of cooperation with the UK, as the UK plays a significant role in unlocking Europe's offshore potential.

Article 13 Joint support schemes: Member States may also set up a new support scheme and agree on the distribution of costs and benefits resulting from this cooperation. Driven by the significant transaction costs going into the setup of the new support scheme such an arrangement would typically include a multi-project approach, but it might also be used for a large single project. The national support scheme does not cease to exist with the implementation of a joint support scheme.

Support scheme

For cooperation projects, three basic options are available regarding the support scheme: either the support scheme of the country where the installation is located can be used, the support scheme of the contributing Member State may be used or are new joint support scheme may be set up. The support scheme includes the site selection procedure, the grid connection regime, the form of support, and the tender design (see the subsequent sections for a detailed discussion). The selection of the support scheme is relevant, regardless of whether actual support payments are necessary or not. Each of these elements may be picked from the host MS, the contributing MS, or be newly defined. However, in practice, it is unlikely that the tender of a host country is chosen while the form of support of the contributing Member State is applied, as the support scheme required a coherent design across these elements.

Financing of support

In most NSEC countries with existing national offshore wind support schemes, costs for granted support payments are recovered through consumers via surcharges on the electricity bill or from state budget, like in the UK. In terms of the entity in charge of paying support to generators, NSEC countries have adopted different approaches, ranging from grid operators taking this role (e.g. Germany, Denmark) to dedicated public authorities or agencies in charge of this (e.g. the Netherlands, UK). The costs will largely be recovered from the end-consumers.

For (joint) hybrid OWPs, support payments need to be refinanced, regardless of which support scheme is used (existing or newly implemented). This may happen either via the host country's levy scheme, the contributing country's levy scheme, or a newly implemented scheme. The participating Member States can contribute a predefined share of the overall support amounts into either scheme. Alternatively, a separate fund can be established and be financially equipped by the cooperating Member States either through their existing refinancing schemes or via direct contributions from their state budget. In addition, to these financing options, EU funds may be added to the support of hybrid OWPs while avoiding overcompensation of installations (for a detailed discussion of EU programmes see task 2.3 in section 3.3).

Transfer of RES statistics

The electricity generated by joint (hybrid) OWPs initially counts towards the Member State's RES share in which the production asset is located. Whenever Member States cooperate on RES deployment and implement one of the cooperation mechanisms, part of the RES statistics are transferred to the contributing Member State. One approach is to distribute the share of transferred RES statistics based on the financial contribution to the support paid to the installation. This approach represents the core functionality of the cooperation mechanisms, but it may omit additional costs and benefits apart from support costs and RES statistics and it would not work in the context of projects not receiving support scheme payments (i.e. merchant projects). In this context, a transfer price would have to be negotiated, similar to the case of pure statistical transfers. The sharing of support costs and transfer of RES statistics is part of the cross-border cost allocation discussed in section 3.2.3.

3.1.3 Basic structure of joint (hybrid) OWPs

Hybrid offshore projects may be set up in a variety of ways. A report by Roland Berger on the benefits of hybrid offshore projects indicates suitable starting points to categorise possible project setups.[212] The report defines various configurations that we subsequently redefine to accommodate cooperation and financing issues. It presents five potential setups:

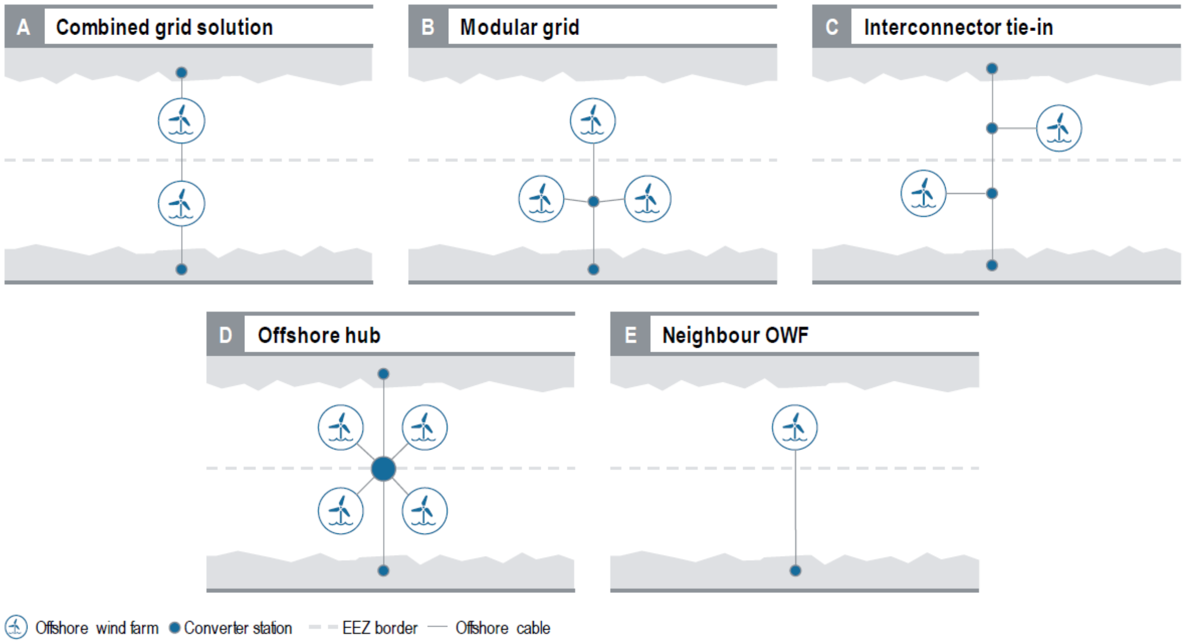


Figure 3-1. Hybrid offshore project configurations (Source RB 2018)

A: Combined grid solution: Connects two offshore wind projects (OWPs) in different EEZs, both of which are individually connected to the shore of their home country. An example is the Kriegers Flak transmission project between Denmark and Germany.

B: Modular Grid: Connects multiple OWPs, located in different EEZs, to shore via a single export cable system. One example is the Modular Offshore Grid in Belgium, which connects several OWPs to shore, even though it lacks a transnational dimension. This project setup is categorised as a hybrid project in the Roland Berger report, whereas in this report this setup would be a potential cooperation case, but not a hybrid OWP as it does not include an interconnector functionality.

C: Interconnector tie-in: Connects one or more OWPs to shore via an interconnector. No examples of this concept currently exist. A hypothetical example studied by Roland Berger is the COBRA Cable hybrid project, which connects a German offshore wind farm to the Dutch and Danish electricity markets via the COBRA Cable interconnector.

D: Offshore hub: Connects multiple OWPs to at least two markets via an offshore hub. The proposed North Sea Wind Power Hub is an example of this concept; it is supposed to connect a larger number of OWPs to several North Sea countries via a hub in proximity to the Dogger Bank area.

[212] Roland Berger, 2018. Hybrid Projects. How to reduce costs and space for offshore developments. https://ec.europa.eu/energy/studies/hybrid-projects-how-reduce-costs-and-space-offshore-developments_en?redir=1

E: Neighbour OWP: Connects an OWP located in the EEZ of country 1 to the shore of country 2. No examples of this concept currently exist. A hypothetical example studied by Roland Berger and discussed in the NSEC is the DE OWP to NL project, which connects a German offshore wind farm to the Dutch electricity market. As project setup B, this setup is categorised as a hybrid project in the Roland Berger report. Again, in this report this setup would be a potential cooperation case, but not a hybrid OWP as it does not include an interconnector functionality.

These configurations are defined based on their infrastructure configuration (their hardware), but they do not define the cooperation software. For each of the five hybrid asset configurations, different cooperation models and responsibilities could be applied. We recommend characterising joint (hybrid) offshore projects along the following structure:

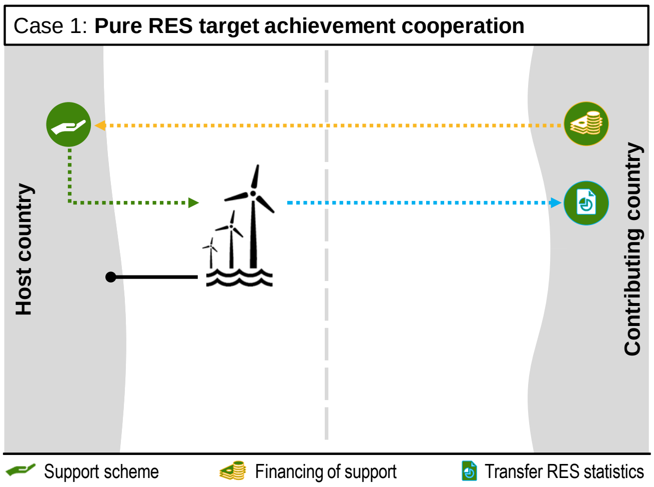
Hardware: For the hardware dimension we suggest to generally differentiate between a project excluding or including interconnector functionality. If a project does not include an interconnector functionality (like in Roland Berger's configurations B and E) it is not really a hybrid OWP as defined above. If no interconnector functionality is provided in the project, a key aspect is whether the generation asset is located in the EEZ of the Member State it is connected to (for instance, in Roland Berger's configurations A and C). It can also be located in another EEZ than that of the Member State it is connected to (for instance, in Roland Berger's configuration B and E), which requires cooperation among Member States, albeit without providing a hybrid functionality.

Alternatively, and core to this report, projects can include an interconnector functionality and so constitute a hybrid OWP. Another core distinction in the hardware setup is whether the projects includes a single OWP (as in configuration E) or multiple OWPs (as in all other configurations).

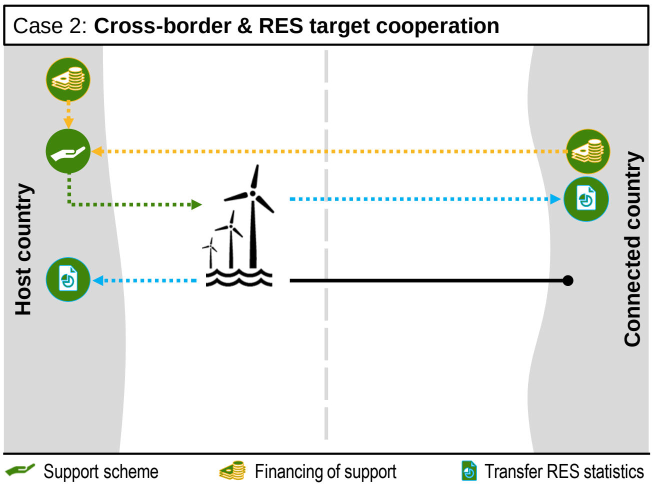
Software: Cooperation software is not an aspect covered by the Roland Berger report (for details on cooperation software, see section 3.1.2). This includes the support/tendering scheme within which a (hybrid) OWP is built, regardless of whether support is actually paid or whether zero-bids are submitted or even defined ex-ante. In this case, several setups are possible. First, the support scheme of the host Member State may be used, i.e. the Member States in whose EEZ the generation asset is located. Second, the contributing Member State support scheme may be used (the Member State providing the potential support payments and/or the project selection procedure). Third, a new joint support scheme may be designed and implemented.

In addition, the support/subsidies (if necessary)—independent from the regulatory support scheme used—may be provided by the host Member State, the contributing Member State, or a mix thereof. As a result, and in line with the cooperation mechanisms of the RED II, the corresponding share of RES statistics may be allocated to the participating Member States. This allocation is part of the CBCA discussed in section 3.2.3, but as a high level upfront decision it defines the basic setup of the cooperation.

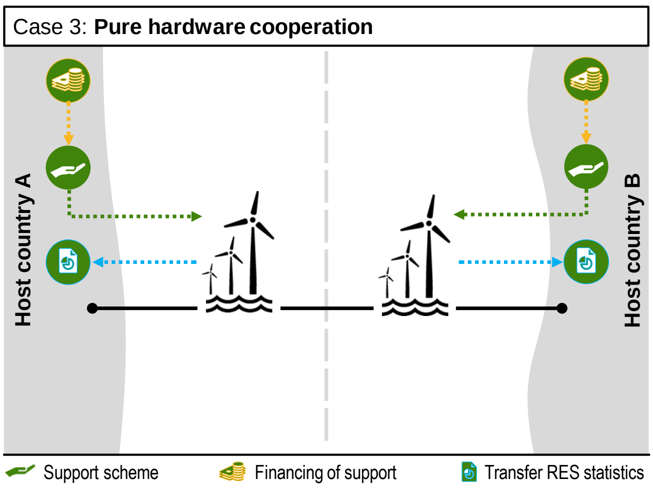
These individual elements can result in many possible project and cooperation configurations. The following setups are sensible cooperation configurations and we will use them throughout the report to develop and illustrate the recommendations.



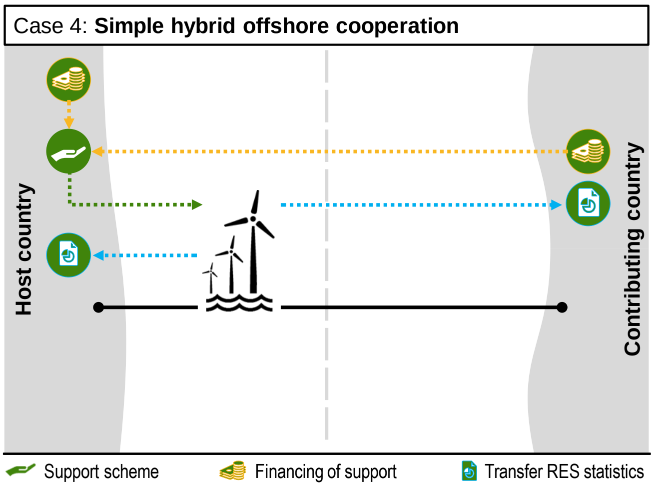
Case 1 RES target achievement: In this setup, no interconnector functionality is part of the cooperation project and the OWP is located in the Member State it is connected to. The host Member State support scheme is used (with or without actual support costs). This case represents a joint project according to Article 9 of RED II. The contributing country pays a defined amount per energy to the host country (for instance, part of the support costs) to receive a corresponding share of the RES statistics resulting from the OWP electricity production. A hypothetical example of this cooperation case may be Luxemburg paying an amount to the Netherlands to receive RES statistics from a specific OWP. The Netherlands transfer these statistics to Luxemburg and may in turn compensate part of grid integration costs of that OWP.



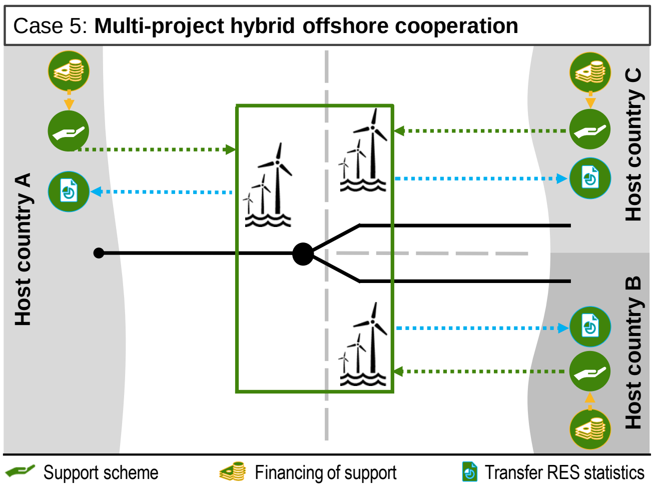
Case 2: Cross-border and RES target achievement: This setup does not include an interconnector functionality, but the OWP is located outside of the EEZ of the Member State it is connected to. The support scheme of the connected country is used (with or without support costs). The host country transfers parts of RES statistics to the Member State the OWP is connected to, to compensate, for instance, integration costs. An example of this would be an OWP located in Germany's EEZ, but connected to the Netherlands.



Case 3: Hybrid - hardware-only: In this setup, the project includes an interconnector functionality. In this case, one OWP is in each of two EEZs and connected to their respective shores while being connected to each other. Each Member State uses its respective support scheme and keeps the RES statistics produced from the OWPs in its EEZ. Examples of this setup include projects like WindConnector, Nautilus, Kriegers Flak, and the Cobra Cable project.



Case 4: Hybrid - hardware and software: This setup includes interconnector functionality. One OWP is in Member State A (host country). The host country's support scheme is applied, but the two Member States the OWP is connected to finance the support. In this case, the RES statistics are transferred from the host Member State to the contributing Member State, according to the agreed share. Examples of such a setup could be a German-Dutch interconnector including wind farm in the Dutch EEZ or the Danish Energy Island, if connected to the Netherlands and / or Germany.



Case 5: Multi-project hybrid - hardware and software: This setup would include an interconnector functionality and could include, for instance, several OWP connected to the interconnector via a hub, one in each Member State (i.e. A, B, and C). In this case, a new support scheme may be implemented (i.e. according to Article 13 of RED II), which would be funded by all three MS. The support could be auctioned centrally by a single dedicated authority or by a cooperation of the involved auction authorities (i.e. energy agencies or regulators). The RES statistics would be transferred according to share of support scheme payments or any other CBCA agreement implemented by the involved parties. The example here is the NSWPH, which includes the Netherlands, Germany, and Denmark.

Many more project setups are possible, but the ones described above reflect comparably realistic options and are aligned with ongoing discussions on cooperation and hybrid OWPs. We use these predefined project setups to derive and structure recommendations in the remainder of the report.

3.1.4 Support scheme design

This section discusses the support scheme design for joint (hybrid) offshore projects. The support scheme design includes process for site selection and pre-development, the grid connection regime, the form of support (and related financing issues), and the tender design.

3.1.4.1 The process for site selection and pre-investigation

Two general models for offshore wind site selection and pre-investigation exist: centralised and decentralised. In a centralised model, a state body undertakes zone and site selection as well as site pre-investigation and pre-development (including surveys and wind measurements) and bears the cost. This information is shared with developers bidding for the site in an auction. This model for site selection and pre-investigation is adopted in the Netherlands, France, and Denmark, as well as the upcoming phases in Belgium and Germany. In a decentralised model, a state body undertakes zone selection, but project developers select sites, perform all required site pre-investigation and pre-development, and bear the cost. This site selection process is currently applied in the UK. In addition, Denmark has an open-door policy where developers can put forward specific projects outside of the central tender scheme.

A model's selection involves a trade-off between de-risking project development while keeping enough flexibility in the site specifications to stimulate innovation and leverage developer experience with selecting profitable sites. In terms of site pre-investigation, some variation exists regarding the responsibilities attributed to the state body or the developer. In general, a minimum level of preliminary and basic site investigation performed by a public authority seems advantageous as it contributes to de-risking developers and it allows for a more controlled rollout of offshore wind capacity to meet deployment targets. In addition, it eliminates the sunk cost of project sites that are not successful in lease applications or auctions in a decentralised model.

Ongoing discussion remains on what level of site pre-investigation should fall under the responsibility of developers. In some NSEC countries, project developers are responsible for more detailed studies and site investigations. For example, in previous offshore wind auctions in France, the national authorities undertook some of the site investigations while the developer was responsible for carrying out the specific environmental impact assessment and obtaining leases. However, the country is now moving towards a more centralised model where in-depth site investigations will be undertaken by public authorities, thereby leveraging the benefits mentioned above.[213]

Appropriate zone and site selection for offshore wind farms can help mitigate consenting issues in a later stage.[214] A recent example is the rejection of Vattenfall's Thanet wind farm extension in the UK.[215] Next to site selection, the consenting and permitting process should be clear in terms of timelines and processes to prevent delays in offshore wind project developments.[216] In a centralised model, a state body can provide a one-stop-shop where the successful developer receives all the required permits and licences to start developments, as is the case in the Netherlands. In other NSEC countries with centralised models, developers are still required for some of the applications, for example, under the previous auction rounds in France.[217]

[213] CMS, 2017. Offshore Wind Law and Regulation in France. https://cms.law/en/int/expert-guides/cms-expert-guide-to-offshore-wind-in-northern-europe/france
[214] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf
[215] Offshore wind biz, 2020. Thanet Extension DCO Application Rejected. https://www.offshorewind.biz/2020/06/03/thanet-extension-dco-application-rejected/
[216] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf
[217] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf

Table 3-1. Advantages and disadvantages of centralised and decentralised site selection and pre-investigation models.

	Centralised model	Decentralised model
Advantages	Holistic planning approach: coordination of site and offshore capacity development De-risking of developers	Freedom for optimal sizing of sites by developers: leveraging developer experience with selecting cost-effective sites
Disadvantages	Too strict development limitations through site specifications might limit innovation Site selection and pre-investigation to be done by a single party that needs to have capacity to timely deliver	High risk for developers: sunk cost of site pre-development for developers unsuccessful in auction Macroeconomic inefficiencies Less government control on offshore capacity rollout

For hybrid projects, cooperation between entities could be beneficial to ensure appropriate site selection and timing of tendered sites and to prevent stranded assets. This cooperation could be delivered under a centralised model and would be harder to attain under a decentralised model. Under a decentralised model, it would be more difficult to plan and coordinate developments due to uncertainty with project realisation timelines, involved stakeholders, and exact locations. Most countries already employ a centralised model for site selection and pre-investigation.

The type of hybrid project determines the extent to which cooperation is required. Shared projects between two countries with different grid delivery models is not uncommon; for example, TenneT and Vattenfall are investigating the feasibility of an interconnector between a TenneT offshore substation in the Netherlands and a Vattenfall wind farm offshore substation, or onshore substation, in the UK.[218] When designing hybrid projects, involved countries should decide early on their preferred grid delivery model and discuss and align explicitly on all the implementation details as cooperating countries may not understand the same definition of roles and responsibilities when referring to a centralised or decentralised model. Another point is the costly pre-development process for hybrid projects relative to the budgets available to the agencies responsible. The stakeholders developing hybrid projects need to agree on who bears the cost for the pre-development and how it is recovered.

3.1.4.2 The grid connection regime

The grid delivery model determines who finances the grid connection and where the interface lies between a developer and the governing TSO, TAO, or OFTO. The adopted regime balances cost to consumers and government control over planning and realisation timelines with de-risking of developers in the various stages of the project. As section 2.2 describes, this includes defining the responsible parties for the construction and financing of the offshore wind transmission assets and the mechanism for the recovery of the costs. Financing of offshore wind transmission assets consist of three key elements: construction, onshore and offshore O&M, and onshore grid reinforcements. The

[218] TenneT, 2018. TenneT and Vattenfall to study potential Dutch and UK offshore wind farm connections https://www.tennet.eu/news/detail/tennet-and-vattenfall-to-study-potential-dutch-and-uk-offshore-wind-farm-connections/

developer-built and TSO-built grid connection regimes are compared in the following sections, along four categories:[219]

1. **Planning and design:** The design of the offshore wind transmission assets needs to be aligned with reliability requirements, cost optimisation, environmental impact minimisation, and optimisation of onshore grid reinforcement needs. In addition, international technical design standards must be met. To prevent stranded assets, it is essential that the planning and design of the offshore wind transmission assets align with the timing of offshore transmission asset development with the planning and realisation of offshore wind farms, and the optimisation of the onshore grid. Only in this way can a timely delivery of the grid connection be guaranteed to offshore wind farm developers.

2. **Commercial and finance:** Offshore wind transmission assets are highly capital intensive. The division of the roles and responsibilities for construction will affect the level of financing required, which can impact the cost of capital of project-financed wind farms.

3. **Construction and interface risk:** The adopted grid delivery model will determine who is responsible for the construction of the offshore wind transmission assets and who will define where the technical and procedural interfaces lie between the developer and the TSO or TAO. Offshore wind transmission assets include both offshore assets (array cables, offshore platforms, and offshore export cable) and onshore assets (onshore export cable and onshore stations). Furthermore, onshore grid reinforcements might also be required to ensure sufficient hosting capacity on the onshore grid. Onshore grid reinforcements in this case are defined as the reinforcements required beyond the onshore connection station. These could include an upgrade of the onshore HVAC grid, or dedicated HVDC corridors transmit power over larger distances.

4. **Operations and reliability:** A successful operational strategy for the offshore wind transmission assets is of importance for both developers and the TSO or TAO to ensure reliability and viability. A high availability of the transmission assets will build and strengthen the TSO's reputation as a reliable grid operator and will avoid monetary penalties to be paid to developers for non-availability of assets. For a wind farm developer, high transmission asset availability will avoid unnecessary revenue losses.

Planning and design

Most NSEC countries, such as the Netherlands, have adopted or are in the process of adopting a more TSO-built approaches to planning and design, although the UK currently has an OFTO-based developer-built model. Denmark is one of the only NSEC countries that is shifting away design responsibilities from the TSO Energinet to the developer starting with the upcoming Thor tender.

Both grid connection regimes have advantages and disadvantages in terms of planning and design of offshore wind transmission assets, as Table 3-2 details.

[219] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en; IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf; WindEurope, 2019. Industry position on how offshore grids should develop. https://windeurope.org/wp-content/uploads/files/policy/position-papers/WindEurope-Industry-position-on-how-offshore-grids-should-develop.pdf

Table 3-2. Advantages and disadvantages of TSO-built and developer-built grid connection regimes in terms of planning and design. *(Source: adapted from Navigant, 2019)*[220]

	TSO-built	Developer-built
Advantages	• Holistic and transparent view on future developments, including short-, medium-, and long-term onshore and offshore grid development needs. This enables proactive grid planning and development, e.g. anticipatory investments. • Optimised grid expansion (including permitting, design, and procurement) and onshore grid reinforcements. • Opportunity to standardise transmission asset design for economies of scale. • Shared assets (a single connection for several wind farms) could reduce environmental impact due to an optimisation of the number of onshore landing points. • Non-mature technologies and strategic projects can be specified and developed (high potential for futureproofing).	• A single party coordinates both offshore wind farm and transmission asset development. • Potential to enhance design efficiencies/compatibility between offshore transmission assets and wind farm for single projects through integrated design, and tailored transmission asset configurations.

[220] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

	TSO-built	Developer-built
Disadvantages	• Standardisation of transmission assets could hamper innovative solutions from developers or the supply chain. • Needs of developers may not be fully reflected in design and procurement process of transmission assets, e.g. capacity for future additions. • Potentially larger and more complex projects, which could increase risk of transmission asset delays for wind farm developers if TSO is not able to timely develop offshore transmission assets.	• Transmission asset development is not the core business of wind farm developers; may limit competition. • Transmission assets tailored to wind farm specificities on a project-by-project basis with a potential higher environmental impact through an increased number of onshore landing points. • Risk of non-future proof system and use of different designs per project, preventing standardisation and asset sharing. • Developers must wait for the TSO to complete onshore grid reinforcements before connection to the grid. Risk of stranded assets for developer remains if TSO is not incentivised for time delivery. • Non-mature technologies are only included if directly cost-effective. • Lack of system perspective: potential onshore capacity reinforcements beyond developer's scope (only under a deep connection regime). Anticipatory investments for future interconnection capacity are not considered when they do not directly support the business case. • Storage and conversion could be included in development, but coordination would be required to mitigate adverse effects (e.g. having to significantly increase connection capacity for onshore electrolysers).

The development of offshore wind transmission assets in hybrid projects could benefit from a more coordinated planning of sites and offshore transmission asset development through a TSO-built grid connection regime due to the scale of offshore wind developments. This would allow the TSO/TAO to take a holistic and systemic planning approach of both offshore assets and potential onshore grid reinforcement needs thereby reducing the risk of stranded assets. In addition, proactive and anticipatory grid planning and development matches better with core activities of TSOs than developers.

A TSO-built regime would also include a reduced number of stakeholders for hybrid project development compared to a developer-built regime, reducing planning and design incompatibilities. However, the adopted regime should also consider using the extensive experience of commercial developers with transmission asset developments to ensure timely realisation of the significant scale up of offshore wind power in the next decades. The complexity of hybrid projects could increase the risk for delayed grid delivery to developers. Developers can play a role in developing storage and conversion solutions to offset required onshore grid reinforcements; however, coordinating these efforts should be considered to mitigate the risk of adverse effects.

Commercial and finance

To our knowledge, all NSEC countries with a TSO-built model have implemented a form of shallow grid cost allocation regime for the offshore wind transmission assets; the costs for the connection are largely borne by the TSO or TAO. In a shallow regime, the developer does not have to include the cost for grid connection in their bid, increasing the probability of zero-bids. By contrast, in a developer-built model, the project developer is responsible for the financing and construction of the grid connection to the shore (deep cost charging regime). Hence, the developer needs to consider the cost for grid connection in its bid.

In the countries with a TSO-built model, costs for offshore wind transmission assets are mostly integrated in the regulated asset base of the TSO and paid for by consumers through grid tariffs. In some NSEC countries with a TSO-built regime, costs are recovered through special levies on the consumers' electricity bill, for example, in the Netherlands and Germany. Some industry stakeholders are more inclined towards models where the developer bears the responsibility for the construction of the transmission infrastructure to concentrate the entire project development with one entity. Others are more hesitant given the increased capital requirements on the developer's side, which may reflect as higher bid prices rather than being borne by all electricity consumer through via higher grid charges.

Both grid connection regimes have advantages and disadvantages in terms of commercial and financing conditions of offshore wind transmission assets, as Table 3-3 details.

Table 3-3. Advantages and disadvantages of TSO-built and developer-built grid connection regimes in terms of commercial and finance. *Source: adapted from Navigant, 2019[221]; Navigant, 2020[222]*

	TSO-built	Developer-built
Advantages	• A government-backed TSO typically has more favourable financing conditions (lower debt and equity return rates) compared to a commercial developer. • Potential cost reduction of procurement and project management costs through stable project pipeline. • Risk of delayed grid connection delivery by TSO could be (partially) offset through compensation scheme to developers. • Operation of multiple standardised grid connections could result in reduced OPEX.	• Cost optimisation on a project-by-project basis. • Developers operate in competitive market environment which results in downward pressure on wind farm and transmission asset costs. • Commercial developers and OFTOs have more flexible financing options, rendering them more competitive than government-backed TSOs. • Flexible financing structures for commercial parties, e.g., higher debt shares, could result in lower WACC than for TSOs.

[221] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

[222] Navigant, 2020. Final report: offshore grid delivery models for Ireland – options paper for offshore wind. https://www.dccae.gov.ie/enie/energy/consultations/Documents/49/consultations/Navigant_Report_Options_Paper_for_Offshore_Wind_Grid_Delivery_Models.pdf

	TSO-built	Developer-built
Disadvantages	• High CAPEX investment for TSOs to develop and operate transmission assets. For state-owned TSOs, governments need sufficient capital available to take on the risk. Investments can be held back if shareholders are hesitant to provide equity. • Construction of all offshore assets by a single party; TSO needs to have sufficient capital to take on risk.[223] • TSOs are not exposed to same competitive cost pressure that developers are driven by to be competitive in tenders.	• Potential higher cost of capital for a commercial party due to increased return rates on equity and increased debt rates, and transaction costs from developer to OFTO. • Cost and investments of transmission assets are not necessarily optimised from a societal LCOE perspective but on an individual project basis.

When financing offshore wind transmission assets in hybrid projects, it is important to minimise cost to the end-consumers. The grid connection regime determines what assets fall under the scope of the developer and are included in their bids. A TSO-built model could reduce cumulative societal cost through optimised use of assets through hubs and increased reliability and renewables integration in the onshore system. Synergies across projects could also reduce development and O&M cost of the hybrid project system through standardisation and innovation.

For strategic projects like hybrid projects, financing conditions are likely more favourable in a TSO-built model than under a developer-built regime due to a lower (perceived) investment risk. Measures should, however, be included to mitigate the risk of over-spending by the TSO to optimise cost to consumers as TSOs are not subject to competitive cost pressures as would be the case under a developer-built regime (assuming a market with enough competition). The TSO expenditures are controlled by the national regulators and anticipatory investments would have to be approved upfront.

Construction and interface risk

The exact interface (connection point) between the developer and TSO may differ. In TSO-built models typically the offshore wind farm and offshore wind farm array cable are to be constructed and financed by the developer (in Germany, an offshore HVAC substation is part of the developer's scope and for wind farms connected to the MOG in Belgium, the developer is additionally responsible for link to the offshore switchyard). The interface lies offshore for all TSO-built models.

The interface between developer and TSO in a developer-built grid connection regime is onshore during construction. Under a developer-built model, the developer does not depend on the TSO for the timely construction of the offshore wind transmission assets in contrast with a TSO-built model. Risk of TSO delays under the latter model can be mitigated by penalty payments from the TSO to the developer in case of delays.

The developer would be dependent on onshore grid reinforcements by the TSO under both models. Both grid connection regimes have their advantages and disadvantages in terms of construction and interface, as Table 3-4 details.

[223] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf (last accessed 19 May 2020)

Table 3-4. Advantages and disadvantages of TSO-built and developer-built grid connection regimes in terms of construction and interface risk. *(Source: adapted from Navigant, 2019)*[224]

	TSO-built	Developer-built
Advantages	• Coordinated and holistic offshore wind deployment and onshore capacity reinforcements by single party (TSO) responsible for both onshore and offshore transmission assets (transmission assets could also include offshore or onshore hydrogen conversion and transmission). Large TSOs can coordinate offshore work across their portfolio. Combining TO and SO tasks can improve efficiency.	• Reduced risk of construction delays due to a single party coordinating offshore wind farm and transmission asset development. • Offshore interfaces during construction managed by the same party, which provides greater control and increased flexibility.
Disadvantages	• Stranded asset in case of construction delays, projects not realised. • A significant offshore interface between developer and TSO.	• Increased project management requirements to address transmission asset developments. • Onshore grid reinforcements still require coordination with TSO.

The construction and interface risks of offshore wind transmission assets included in hybrid project are balanced for either TSO-built or developer-built grid connection regimes. A TSO-built model provides opportunity to coordinate and optimise offshore and onshore transmission asset development while a developer-built model provides a less complex interface that lies onshore. However, a key finding for hybrid projects with several countries collaborating is that these countries need to explicitly coordinate the responsibilities for construction and the exact interface between the developers and TSO. Different grid connection regimes between countries could increase complexity, which could lead to delays in the construction process and additional risks in the interface management.

Operations and reliability

In most NSEC countries, the party responsible for the construction and financing of the offshore wind transmission assets is also responsible for operation and maintaining reliability and availability. One exception exists under the developer-built OFTO model in the UK. There, the developer is responsible for constructing the offshore wind transmission assets and will sell these off to an OFTO after commissioning. The OFTO is then responsible for maintaining reliability and availability of the assets. The NETSO is responsible for operation of the assets.

Both grid connection regimes have their advantages and disadvantages in terms of operations and reliability of offshore wind transmission assets, as Table 3-5 details.

[224] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

Table 3-5. Advantages and disadvantages of TSO-built and developer-built grid connection regimes in terms of operations and reliability. *(Source: adapted from Navigant, 2019)*[225]

	TSO-built	Developer-built
Advantages	• Greater control over grid operation by transmission responsible party. • Reduced number of involved stakeholders along the value chain. • Reliability determined by the government. • Availability of offshore wind transmission assets is incentivised through specific mechanisms; part of the financial claim shall be borne by the TSO. • Potential OPEX reduction due to a larger asset base and standardised equipment.	• Risk of transmission asset failure lies with party most affected (does not apply to the UK OFTO regime). • Reliability is incentivised through direct revenue impact (non-OFTO) or an availability target (OFTO). • In case of non-OFTO developer operated projects, O&M of the wind farm and grid connection can be aligned.
Disadvantages	• Regulatory framework needed to incentivise high availability of the grid connection system. • Unavailability penalties might be less effective with a large publicly owned organisation as ultimately costs could be (partially) socialised.	• Mismatch between operating duration of the transmission asset, which is typically longer than that of the offshore wind farm. This could leave utilisation of the full asset lifetime in the long term uncertain. • In case of OFTO regime in the UK, the availability penalty is capped up to 10% of annual revenue.

Offshore wind transmission assets in hybrid projects could benefit from higher redundancy in the design compared to single-line wind farms due to hubs and meshed connections. Developers and TSOs have different incentives to maintain reliability and especially in a TSO-built (or OFTO) regime an appropriate penalty scheme should be included for transmission asset unavailability. Developers are incentivised to keep transmission assets operational and available, as unavailability negatively impacts their revenues. When a developer-built model would be applied to hybrid or shared assets developments, issues might arise due to unbundling requirements (Directive on common rules for the internal market for electricity [EU] 2019/944) that restrict generation and operation by a single party, in this case, the developers. The ownership and operation of shared assets may then have to fall under the responsibility of the TAO/TSO.

Conclusion

The key considerations for a grid connection regime for offshore wind transmission assets included in hybrid projects were identified as:

- **Planning and design:** Hybrid projects could benefit from a more coordinated planning of sites and offshore transmission asset development (including anticipatory investments, and innovations such as hydrogen conversion and transmission) through a TSO-built grid connection regime due to the scale of offshore wind developments. However, the adopted regime should also consider leveraging the extensive experience of commercial developers with transmission asset developments to ensure timely realisation of the significant scale up of offshore wind power in the next decades. The complexity of hybrid projects could increase the risk for delayed grid delivery to developers.

- **Commercial and finance:** A TSO-built model could reduce cumulative societal cost through optimised use of assets through hubs and increased reliability and renewables integration in the onshore system. Measures should be included to mitigate the risk of TSOs overspending

[225] Navigant, 2019. Connecting offshore wind farms: A Comparison of Offshore Electricity Grid Development models in Northwest Europe Commissioned by: Réseau de Transport d'Électricité and TenneT TSO B.V. https://guidehouse.com/-/media/www/site/downloads/energy/2019/2019-navigant-comparison-offshore-grid-development.pdf?la=en

to optimise cost to consumers, as TSOs are not subject to competitive cost pressures as would be the case under a developer-built regime. Anticipatory investments would be subject to upfront approval by the regulator.

- **Construction and interface risk:** The construction and interface risks of offshore wind transmission assets (which could also include hydrogen conversion and transmission infrastructure) included in hybrid project are balanced for either TSO-built or developer-built grid connection regimes. A TSO-built model provides opportunity to coordinate and optimise offshore and onshore transmission asset development while a developer-built model provides a less complex interface which lies onshore. However, a key learning for hybrid projects where several countries would collaborate is that collaborating countries need to explicitly coordinate the responsibilities for construction and the exact interface between the developers and TSO.

- **Operations and reliability:** Offshore wind transmission assets included in hybrid projects could benefit from higher redundancy in the design compared to single-line wind farms due to hubs and meshed connections. Developers and TSOs have different incentives to maintain reliability and, especially in a TSO-built (or OFTO) regime, an appropriate penalty scheme should be included for transmission asset unavailability.

For radially connected OWPs a developer-built (i.e. decentralised) approach may be suitable to make use of the developers incentives for cost-efficiency. For joint (hybrid) OWPs and especially in hub solutions, a centralised approach appears to be beneficial. The need to identify the adequate interconnector setup, which cannot connect to an arbitrary number of OWPs, appears to require a centralised approach. As a result, in the following sections we generally assume a centralised model, i.e. preselection of zones and/or sites and a TSO-led approach to building the required infrastructure components, as well as the allocation of support on the basis of site-specific tenders.

3.1.4.3 Form of support and related financing issues (e.g. PPAs)

Support for offshore wind can come in various forms including fixed premiums, sliding premiums, CfD, or upfront investment aid. In line with European regulation encouraging their use (with few exceptions), most NSEC countries have implemented support schemes that require direct marketing of the produced electricity combined with (asymmetric/one-sided) sliding feed-in premiums or a (symmetric/double-sided) CfD. Renewable energy plant operators receiving such feed-in premiums have to sell the electricity generated directly on the wholesale power market and receive an additional payment on top of a reference electricity market price. Upfront investment support (€ per kW) is another form of support; however, it is used less in the context of offshore wind support.[226]

In this section, we describe the different forms of support and provide a high level assessment of their applicability in the context of supporting (hybrid) OWPs. Figure 3-2 details these different types of support.

[226] Note that investment support for offshore wind may become more relevant in the future, in case OWP apply for support under the new Connecting Europe Facility funding line for cross-border renewable projects or participate in the EU RES financing mechanism.

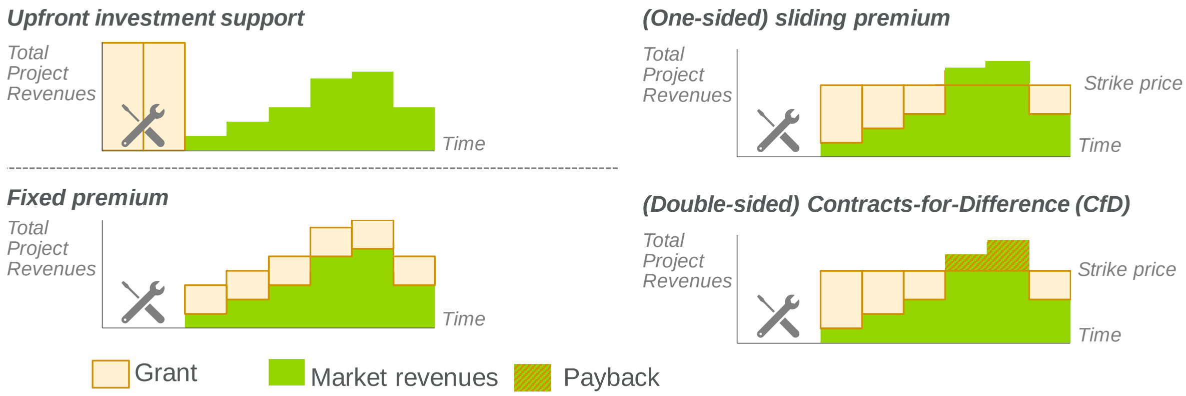


Figure 3-2. Overview of forms of support

A **fixed feed-in premium** provides a fixed remuneration component per electricity produced on top of market revenues. Hence, fixed premiums will result in support payments regardless of how power market prices develop (in case of non-zero bids). The design of fixed tariffs is simple, since no timeframes for reference market price determination are needed as in the case of sliding premiums.

Upfront investment aid entails a fixed upfront payment that is related to installed capacity (i.e. € per kW). Since support does not have to be paid over longer periods, the disbursement of upfront investment support incurs less administrative burden compared to operating aid.

A (one-sided) **sliding feed-in premium** is paid as a difference between a strike price determined in an auction and a reference market price. The reference market price can be determined on an annual, monthly, daily, or hourly basis. The sliding premium is asymmetric/one-sided since support is paid as long as the strike price is above the market price, but no support is paid back by the developer if the market price exceeds the strike price (as in the symmetric/double-sided CfD). Hence, support payments only occur if power market prices are below the strike price. The design of (one-sided) sliding feed-in premiums is more complex than that of fixed feed-in premiums and upfront investment aid and requires the determination of more design elements. These design elements may include the reference period to determine average market prices, and, if applicable, the price zone used to determine the reference value (e.g. the relevant bidding zone). Transaction costs for the support counterparty increase compared to a fixed premium as a result.

CfD, also called symmetric or double-sided sliding feed-in premiums, require the support counterparty to pay the difference between the strike price determined in an auction and the electricity price to the producer if the market price is below the strike price. When the market price is higher than the strike price, the producer needs to pay back the resulting difference to the support counterparty. This payback requirement on the part of the generator is the major difference between a (symmetric/double-sided) CfD and an (asymmetric/one-sided) sliding feed-in premium. As a result, net support payments only occur if power market prices are structurally below the strike price. Similar to a sliding feed-in premium, the reference market price can be determined on an annual, monthly, daily, or hourly basis. Despite offering limited market integration incentives for producers, (double-sided) CfDs are often determined on an hourly basis for practical implementation reasons, since reference periods longer than 1 hour (i.e. weekly, monthly, annually) usually create unintentional effects that distort the dispatch signal.

A negative premium would result in installations stopping production at positive market prices whenever the market price drops below the positive value of the negative premium, since producers would otherwise incur a financial loss. However, there are options to mitigate such distorted dispatch signals, either by suspending negative premium payments whenever electricity prices drop below the value of the negative premium (i.e. no payment if negative premium is higher than market price) or by determining the CfD independent of the actual infeed (even though this brings its own implementation challenges). The (hourly) recalculation of CfDs also increases transaction costs compared to fixed premiums.

Market price risk exposure under different forms of support

In general, types of support can be differentiated according to the associated market risk sharing between renewable energy power plant operators and society/consumers (the implied revenue certainty versus market integration incentives for RE generators). The concrete design of the feed-in premium, that is, fixed premiums (asymmetric/one-sided), sliding premiums, or CfDs (symmetric/double-sided sliding feed-in premiums), determines the degree to which the plant operators assume market price risks. In general, higher market price risks for the plant operators imply higher financing costs for renewable plants (and hence higher support costs) but stronger market integration incentives.

Under fixed premiums, offshore wind generators need to consider the long-term average electricity price impacting overall project revenues when determining their bid price. At the same time, OWPs benefitting from fixed market premiums need to bear full market risks, which increases revenue risk and the cost of capital resulting from higher risk premiums compared to a sliding premium or CfD system that hedges this risk. As a result, market integration for both operational and investment decisions are incentivised.

Upfront investment aid covers part of the project's CAPEX and so reduces the required financing volume, which may decrease overall capital costs. Moreover, upfront investment aid implies similar market integration incentives to fixed premiums. At the same time, unlike in asymmetric sliding premiums and CfDs, projects are exposed to full short- and long-term electricity market revenues risks, which increases financing costs.

Compared to a fixed feed-in premium, a (symmetric/one-sided) sliding feed-in premium reduces revenue risks for producers, which also reduces risk premiums on financing costs. The extent of revenue risks depends on the share of uncertain revenues the bidder considers in its bid. Generators may decide to bid for a floor price under a (asymmetric) sliding premium and expect additional market revenues on top of the support payment or expect to be fully commercially viable based on market revenues. Such considerations are increasingly common as bidders factor in market revenues and bid for a floor price to secure their investment, which may even be zero, rather than bidding a fully cost-reflective price. Under (one-sided) sliding premiums, generators are still exposed to market price signals; however, they are limited to dispatch decisions since they do not expose renewable energy generators to the risks of long-term market price development (but bidders may still decide to carry this risk to have a competitive advantage, i.e. bid lower prices). With an increasing timeframe set for the period to determine the reference market price (e.g. annual), renewable energy generators need to bear more short-term price risks similar to those incurred in the case of a fixed feed-in premium. By contrast, the shorter the set timeframe for the reference period, the higher revenue certainty and the lower market integration incentives will be.

The payback requirement for producers in the case of (double-sided) CfDs ensures that revenues above the level required to make the investment are limited. Since market prices above the strike price reduce the overall revenue, strike prices are usually higher under CfDs compared to (asymmetric/one-sided) sliding feed-in premiums. In other words, generators bid for a floor price under a (asymmetric/one-sided) sliding premium and may expect additional market revenues (or expect to be fully commercially viable based on market revenues), while they need to bid a fully cost-reflective price under a CfD scheme. Although a CfD incentivises cost-reflective bidding behaviour, it does not necessarily result in net support payments if in sum the market revenues are equal to or exceed the generation costs. Particularly in the case of hourly reference market prices, a CfD provides high revenue certainty, which implies a decrease in capital and financing costs for project developers. However, this comes at the expense of lower market integration incentives compared to other forms of support. In this context, (asymmetric/one-sided) sliding market premiums provide benefits compared to (symmetric/double-sided) CfDs in that bidders are free to choose different degrees of market price hedging in line with their ability to take over market revenue risks and to rely on (a larger share) of market revenues. That is, market price exposure and market integration will be high when bidders submit zero bids (i.e. no support payments are required) and can be calibrated at higher levels depending on the level of the floor price that is set by submitting a (positive) bid price.

The risk of the winner's curse under different forms of support

With forms of support that involve long-term price forecasting (e.g. fixed premiums, upfront investment aid), the risk of the winner's curse increases compared to a (one-sided) sliding premium assuming cost-reflective bid prices or (double-sided) CfDs that encourage a cost-reflective bidding behavior. The winner's curse occurs when awarded support later turns out to be insufficient to ensure the project's commercial viability, leading to the project's nonrealisation. This is the case because bidders are subject to significant uncertainties since they need to engage in long-term price forecasts. Such risks may increase in cases of single-item site-specific auctions for offshore hybrid assets, in which several bidders compete for the right to construct their installation at one specific pre-developed site, since competing bidders may have similar cost and revenue expectations. Given that most offshore hybrid projects will likely be subject to a centralised site selection and pre-development (see section 3.1.4.1), this additional risk should be considered. Moreover, the large scale, high coordination requirements and long lead times of (hybrid) OWP highlights the importance of ensuring high realisation rates and so minimising the risk of the winner's curse (e.g. by implementing adequate pre-qualification requirements and penalties; see section 3.1.4.4).

The impact of the market design on the support scheme for hybrid OWP

The support scheme design for hybrid offshore projects may be affected by the market arrangement that defines how offshore wind farms are allocated to specific bidding zones and how interconnection capacity between these bidding zones is allocated. This particularly applies if offshore wind farms bid into a newly created OBZ rather than their respective HZs (see section 3.1.1).

OWPs subject to an OBZ may incur higher price risks because project developers have to anticipate/ forecast the prices of all adjacent bidding zones, not just their HZ. An additional revenue risk is related to negative prices: The OBZ will converge with negative prices in any of the adjacent bidding zones and would experience more negative prices than each of the single bidding zones. Negative prices result in self-curtailment of the OWP and related income losses. This situation poses an increased revenue risk compared to a curtailed OWP within a HZ, which would receive compensation for the curtailed electricity production. Both sources of revenue certainty may result in higher risk premiums and so require forms of support that provide a certain level of revenue risk hedging for producers, such as an increased revenue stability.

Forms of support create different degrees of market integration incentives and so provide different levels of revenue certainty. If the aim is to increase revenue certainty for OWP located in an OBZ, fixed premiums and upfront investment support may be less suitable, given that generators subject to these forms of support need to bear full market risks and have to anticipate long-term market values, i.e. revenue risk hedging is low compared to other forms of support (such as one-sided sliding premiums or double-sided CfDs). This may lead to higher overall support costs and, given the revenue uncertainty, disincentivise developers to bid in the first place, which could have negative effects on competition levels.

By contrast, given their inherent ability to hedge revenue risks for the generator (one-sided) sliding feed-in premiums and (double-sided) CfDs are better suited to address a potentially increased revenue uncertainty of OWPs located in OBZ. The revenue uncertainty under these forms of support are usually borne by the government/society, unless zero bids are submitted or, to a lesser degree, if producers share the risks by submitting bids below cost as in the case of asymmetric sliding premiums. Double-sided CfDs provide the highest revenue risk hedging potential compared to all other forms of support; however, at the expense of low market integration incentives (especially with an hourly calculation). Under an (asymmetric/one-sided) sliding premium, generators are free to decide to bid on a (positive) floor price and expect additional market revenues on top of the support payment or, in case of zero bids, rely on market revenues alone. The degree to which market revenue risks can be taken over by project developers (i.e. the extent of market integration incentives) as signalled by submitted bid prices can be reflected in auction results. Setting shorter timeframes for the reference period increases revenue certainty (but reduces market integration incentives). If the goal is to limit revenues risks for producers, shorter timeframes are more suitable. On the other hand, higher revenue risks (induced by setting longer reference timeframes), may trigger the incentive to include additional revenue options into the project setup such as hydrogen (see section 3.1.5).

In a dedicated OBZ, the market price is equal to the price of the bidding zone to which no congestion exists. In most circumstances, this will be the bidding zone with the lowest market price. Compared to a situation in which an OWP is integrated in a HZ, this structurally decreases revenues for offshore operators. As a result, higher support payments compared to an OWP in an OBZ may become necessary independent of the chosen form of support.

Previous offshore tenders (e.g. in NL, DE—not necessarily in all NSEC countries) have demonstrated that under favourable conditions, zero bids under (asymmetric/one-sided) sliding premiums are generally possible. In those instances, project developers indicate that they do not require support payments and can rely on market revenues alone. A recent study noted offshore wind power generation can be considered commercially competitive at good sites in mature markets.[227] Based on analysis of harmonised auction results from five countries, over the past 5 years, bid prices for power from OWPs across Northern Europe fell by 11.9% ± 1.6% per year. If this trend continues, subsidy-free wind farms may be common in 2023/2024.

Zero bids can be attributed to several factors and site conditions that keep the cost to developers down and mitigate and reduce their risks in these markets (see also section 2.1.3.7). With the recent zero bid tenders, the cost of the grid connection was allocated to the TSO, shifting the risks and costs away from the developer. As a result, the related costs do not appear as support costs but are refinanced via grid fees from consumers. In addition, site selection and pre-development were conducted by a state body, providing a one-stop-shop for the award of concession, permit and grid connection with a successful bid. In the case of multiple zero bids, additional quantitative or qualitative selection criteria become necessary to allow for a differentiation of bids under sliding premiums (i.e. a second bidding component such as the one planned in future German offshore auctions). In the context of hybrid offshore projects located in an OBZ, zero bids are less likely; however, as a result of their structurally lower income and potentially lower revenue certainty. Hence, the prediction of subsidy-free wind farms in 2023/2024 should be considered with caution, as the level of subsidy as determined in auctions depends on future wholesale electricity prices, which may be lower for (hybrid) OWP located in OBZ.

The impact of higher project development risks on the level of support for hybrid OWP

Hybrid OWPs may be subject to higher project development risks than other renewable energy projects, as a result of coordination risks (e.g. the timely and coordinated realisation of the necessary transmission infrastructure) and the increasing use of sites far offshore. Resulting risk premiums may increase costs at project level and so the LCOE of these OWPs. Depending on wholesale market price development, the required level of support may be higher than without such project development risks. Hence, support schemes are likely to remain necessary in the upscale of (hybrid) offshore capacities, including for less mature technologies such as floating offshore and in the case OWPs are located in OBZs.

Impact of central site selection on the form of support for (hybrid) OWPs

As section 3.1.4.1 discusses, hybrid offshore projects would likely be subject to a central site selection and auctioned as part of site-specific, single-item auctions. This has implications for the form of support, since the market integration benefits of some types of support are generally less relevant in this case.

Fixed premiums and upfront investment aid imply market integration incentives for operational and for investment decisions for the selection of an optimal project site and price zone. In site-specific tenders, the optimisation of investment decisions towards locations and price zones with the highest market values is pre-determined; however, all auction participants bid on the same project at the same project site. For investments in offshore hybrid assets where a centralised site selection and pre-investigation is likely, the incentive to build projects in price zones promising higher market values under fixed premiums and upfront investment support is less relevant. A similar argument applies even when sites are not pre-selected but all available sites are within the same bidding zone, since an

[227] Jansen et al. (2020). Offshore wind competitiveness in mature markets without subsidy. In: Nature Energy. Vol. 5. August 2020. 614-622.

optimisation of investment decisions towards other price zones with higher market values is not possible in this case.

PPAs and broader issues of financial engineering for (hybrid) OWPs

Addressing revenue risks may become increasingly important for (hybrid) OWP because of decreasing technology costs of OWP and other favourable developments that resulted in several zero-bids in auctions in Germany and the Netherlands. In the Netherlands, tender rounds have been implemented without offering support at all, selecting projects in the basis of a multi-criteria assessment.[228] OWPs are fully exposed to revenue risks and need to address them to access finance and to limit financing costs. [229]

If an OWP is to be developed in an OBZ, it faces structurally lower revenues and higher revenue risks compared to a HZ solution. This issue may be addressed by the support scheme design if an asymmetric sliding premium or a CfD is applied. However, in case of merchant projects (i.e. no support scheme or zero-bids) and when fixed premiums or upfront investment aid are applied, revenue risks need to be be dealt with by the market. Additional elements fundamentally impacting market revenues include CO_2 prices and energy demand. The latter depends on macroeconomic developments and the related uncertainty has been evident in the wake of the economic downturn as a result of the COVID-19 pandemic.

From a developer's perspective, one approach to addressing revenue uncertainty is to implement PPAs. The degree to which a PPA shifts revenue risks away from the developer and investor (and to whom) depends on its setup and design details. RES PPAs are an established instrument in the US to trade electricity and have emerged in Europe in recent years. In a PPA, a buyer closes a contract with a seller, covering the entire of parts of the electricity production. The buyer can be an energy supplier or a final consumer, e.g. a large corporate consumer (hence a corporate RES PPA). The seller can be the producer or an intermediary, but the exclusion of intermediaries is often seen as an advantage of PPAs.

Two basic options are sleeved/physical vs. synthetic/virtual PPAs. In the virtual or synthetic PPA (occasionally called a financial fixed-for-floating swap contract), the RES producer sells electricity to the power exchange and the consumer buys electricity from the power exchange (or through his regular energy supplier). Both parties enter a CfD (not to be mistaken for the support scheme): if the price at the power exchange is lower than strike price agreed in the PPA, the consumer pays the delta to the RES producer. If the price at the power exchange is higher than the agreed strike price, the RES producer pays that delta to the consumer. This way, both parties end up with an equally distributed price risk, although the electricity trading happens for both parties separately through the electricity exchange (instead of over the counter).

Elements such as basic pricing options (e.g. fixed price, market indexed price with floor/cap, or CfD), the tenure (e.g. 5, 10, 12, or 15 years), review clauses (to check market adequacy after 5 years and to be able to adjust prices if necessary), counterparty risk and offtaker of last resort/supplier of last resort (if either party exits contract due to bankruptcy), and penalty clauses determine how risks are distributed between the involved parties (i.e. who takes up the project development risks, the revenue risk, the balancing risk).

[228] For instance, the selection criteria for Hollandse Kust Zuid 1 & 2 focussed on risk assessment and risk mitigation along the entire project development (i.e. including design, construction, operation and market risks). The assessment took the quality of mitigation measures proposed by the bidders into account. In addition, the Netherlands Enterprise Agency (RVO.nl) included knowledge and the amount of previous experience that developers had into account. Moreover, the design of the offshore wind farm and project capacity (higher proposed output scored more points) was reflected.

[229] It is important to note that the tenders without resulting support payments were possible under specific circumstances, e.g. shifting grid connection costs out of the tender to the TSO, favourable permitting procedures and near-shore sites with very good wind resources.

In the context of (hybrid) OWPs, PPAs may play a role to mitigate revenue risks for developers, reducing the risk in the context of zero-bids and under support schemes that expose bidders to market risks. The role of PPAs for the successful implementation of OWPs has been recognised in a tender in the Netherlands for the Hollandse Kust Noord wind farm area. Without support payments in this tender, 18 out of 100 assessment points could be scored on identifying, analysing, and mitigating risks related to the financial returns on produced power. PPAs can play a crucial role here. Vattenfall won the tenders for Hollandse Kust Zuid 1+2 and Hollandse Kust zuid 3+4 (together approximately 1.5 GW) and as mentioned above their risk management was one of the decisive factors.[230] Other examples of PPA in combination with OWPs include:

- Deutsche Bahn (the Germany's main railway company) signed Germany's first offshore PPA in 2019 with the OWP Nordsee Ost, covering 25 MW of the total of 295 MW capacity over the period of 5 years.
- In 2019, Orsted closed a PPA with Covestro, covering 100 MW capacity of the OWP Borkum Riffgrund 3 (out of 900 MW) over the periods of 10 years.
- In 2020, Danske Commodities closed a PPA with Dogger Bank covering 480 MW of capacity over the period of 15 years (out of envisaged 3.6 GW capacity of Dogger Bank A, B, and C).

Although PPAs may successfully reduce the revenue risk of OWPs, any risk taken away from the OWP and from the public (in the absence of support payments) will have to be distributed between the producer and the consumer (or the energy supplier in case the PPA is not closed with the final consumer). This may be possible when the producer or consumer has an adequate balance sheet and capabilities to trade electricity and be balancing responsible. However, the market potential for direct offtake contracts between producers and final consumers is potentially limited to large and energy-intensive companies and large utilities/energy suppliers. In addition, energy traders and suppliers who may help to standardise PPAs and make them accessible for smaller commercial consumers have limits in terms of their capability to hedge long-term price risks resulting from long-term fixed-price PPAs. For some offshore projects, PPAs may reduce the revenue risk but given the scale of required offshore deployment until 2030 and ultimately 2050, PPAs appear to be one part among others to provide needed revenue stability.

The share of offshore deployment to which PPAs can provide the required revenue stability is difficult to determine. It depends on various factors, including:

- The overall available balance sheet and capabilities to manage market price risks of producers, energy providers, and final consumers.
- The overall demand for PPAs of consumers (which in turn depends on voluntary renewable energy sourcing commitments of large consumers).
- The share to which the demand for PPAs is covered by offshore vs. onshore technologies.

OWP development based on PPAs could be supported via credit enhancement mechanisms, i.e. in the form of an insurance coverage, short-term liquidity instruments, or by underwriting corporate offtake agreements for small and medium sized enterprises. This way, third parties can be responsible for risk that cannot be borne by the offtaker.

For the remaining share of offshore deployment, revenue stabilisation may still have to be provided via support schemes (i.e. asymmetric/one-sided sliding feed-in premiums or symmetric/double-sided CfDs). Such stabilisation does not necessarily imply actual support payments, but rather safety nets to ensure minimum levels of revenues which in turn improves access to capital and reduces the cost.

[230] offshoreWIND.biz, 2018. Vattenfall Shines More Light on Hollandse Kust Zuid 1 & 2 Win. https://www.offshorewind.biz/2018/05/03/vattenfall-shines-more-light-on-hollandse-kust-zuid-1-2-win/

The revenue prospects for OWP may change whenever PtX solutions are added (see section 3.1.5), largely depending on how hydrogen production is supported via quotas or direct support.

A note on the impacts of measures against the COVID-19 pandemic

Europe's countermeasures to the COVID-19 pandemic began in March 2020, and resulted in an economic slowdown. This has led to impacts on the energy sector and more specifically on RES deployment onshore and offshore.[231] The impacts include decreased energy demand, which in turn increases the RES share in EU Member States. More EU Member States are meeting their 2020 RES targets without additional policy action than anticipated prior to the pandemic and its countermeasures. Decreased demand has also led to decreasing wholesale market prices, which may have negative impacts on the business case of merchant RES projects, i.e. projects mainly or entirely relying on electricity market revenues.

The mid- to long-term effects of the pandemic and its countermeasures cannot be easily foreseen, but the unexpected decrease in energy demand and change in energy prices has shown that revenue risks need to be addressed in a financing framework for (hybrid) offshore projects. With a view to the role of PPAs in offshore deployment, this development shows the vulnerability of purely merchant projects. It also highlights the need for improved risk mitigation instruments and potentially backup support schemes.

The impact of national policy preferences on the type of support for (hybrid) OWP

Beyond the assessment of the technical suitability of individual forms of support, their applicability for hybrid offshore projects may depend on national policy preferences, support scheme legacies, and existing path dependencies. For example, reaching political acceptability may be particularly challenging if Member States have to agree on setting up a new support scheme (Case 5 – Multi-project hybrid - hardware and software, see section 3.1.3), especially if the design of existing support schemes of the participating Member States differ strongly from each other. Moving to a new support type may be challenging in terms of political/societal acceptance if it is perceived as fundamentally different from the current national support scheme. This may be the case when moving from a CfD scheme towards types of support providing less revenue certainty or when moving from a sliding premium (with several tenders having resulted in zero-bids) to a CfD (with less exposure to market price signals). A similar challenge may arise in case an existing support scheme is used (Case 4 – Hybrid - hardware and software), which is perceived as fundamentally different from the one the financially contributing Member State uses (e.g. shifting from an asymmetric sliding premium to a symmetric CfD scheme).

Duration of support

NSEC countries allocate support payments for offshore wind with a cap on duration or full load hours (production). Both support payments have advantages and disadvantages as Table 3-6 presents. Support duration in NSEC countries and the UK varies between 15 years (e.g. the Netherlands and the UK) and 20 years (e.g. Germany and France). Denmark defines the maximum number of full-load hours (FLH) during which support is granted regardless of the duration. In shorter support periods, a FLH approach allows developers to stop the clock when the installation is not generating (e.g. at times of negative prices, due to curtailment, no wind, or in case of heavy storm that forcing installations to cut their production temporarily).

All NSEC countries allow concession periods beyond the period in which support is provided (for the first offshore phase in Belgium these periods are equal). This longer concession period allows developers to maximise electricity output and market revenues over a longer period to strengthen their business case. A recent development in the NSEC countries is an extension of concession

[231] Fabian Wigand et al. 2020. Policy Brief, May 2020, Impact of COVID-19 on Renewable Energy Auctions. http://aures2project.eu/wp-content/uploads/2020/05/AURES_II_Policy_Brief_Covid-19.pdf

periods for offshore wind. For example, the Dutch letter to parliament from 26 May announced an extended permit duration for offshore wind to 40 years (see section 2.1.3.7).

Table 3-6. Advantages and disadvantages of support duration cap.[232]

	Duration cap	Production cap
Advantages	Government can predict the duration of support payments.	Developers can stop the clock during periods of curtailment, non-availability of the wind farm, and zero-prices in the market.
Disadvantages	High government spending with high full load hours, support not directly coupled to production.	Government has less control over the duration and phasing of the support payments. A production cap incentivises an adaption of the wind installation design (incentivising a non-intentioned over-dimensioning of the rated wind turbine power).[233]

Hybrid projects might include offshore wind farms located further offshore with increased technical challenges, such as the integration of HVDC circuit breakers. A longer concession period (in line with the recent extensions in the Netherlands) of around 40 years would be beneficial for hybrid projects since they are potentially more capital intensive and this would allow more time for cost recovery. The choice of support cap depends on stakeholder perspectives in a specific project.

Summary: Form and level of support required for (hybrid) OWP

Whether support payments are required for OWP depends on various factors putting costs and expected revenues in relation to each other, such as coordination risks, site quality, proximity to shore, whether grid connections are included in the bid or not, permitting procedures, expectations on future wholesale market prices, and marketing routes that may transfer some of the revenue risks away from the producer (such as in PPAs).

Whenever these impact factors are favourable, merchant offshore projects may be feasible, as the recent past shows. Merchant projects may be realised within various schemes, such as in an open door scheme where the developer initiates the entire project idea (incl. potentially site selection and grid connection), a sliding premium (or theoretically fixed premium or investment support) scheme with zero or even negative bids or a tender without any support (defined ex-ante), and a multi-criteria selection of the projects. In addition, PPAs and other financial engineering approaches may distribute the risks from the support scheme (i.e. society) to the producer and offtaker (energy supplier or final consumer), but this shift of risks has balance sheet implications for the offtaker if the PPA is based on a fixed price.

While there is some potential for risks being redistributed in merchant projects, part of the offshore deployment is expected to rely on societal risk insurance and the continued necessity of support schemes. In the context of increasing offshore capacities up to 450 GW in Europe until 2050, OWPs are likely to move further away from the shores and to be partially implemented as hybrid projects. Hybrid offshore projects may be subject to additional project development risks (e.g. sites far offshore, increased coordination risks). On a project level this may increase the LCOE of these OWPs and thus (depending on wholesale market prices) impact the level of support and societal risk hedge required, limiting the potential for purely merchant projects. Moreover, EU financial assistance in addition to

232 IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf
233 EC, 2014. Design features of support schemes for renewable electricity. https://ec.europa.eu/energy/sites/ener/files/documents/2014_design_features_of_support_schemes.pdf

national/joint support schemes may become relevant, especially if (hybrid) OWPs are located within an OBZ. In this case, EU support on top of national/joint support may be warranted to partially compensate higher support costs resulting from the structurally lower revenues for such OWPs.

Separate from whether actual support payments are required is the issue of whether a support scheme serves to provide a hedge against revenue risks. This is the case when in an asymmetric/one-sided sliding premium, the strike price is below the expected long-term wholesale market price, thus serving as a safety net (assuming non-zero bids). In a symmetric/double-sided CfD, this occurs when the strike price is at or below the level of expected long-term wholesale market prices.

Which form of support is recommendable depends on the impact factors mentioned above. For projects with relatively favourable conditions and limited risks either no support, a low fixed premium or upfront investment aid (albeit at potentially higher support costs compared to a de-risking scheme, e.g. a double-sided CfD) may be a suitable solution. For projects with higher revenue and project development risks (such as OWP further offshore or within an OBZ) addressing long-term revenue risks via a support scheme appears reasonable. This may be done by means of an asymmetric/one-sided sliding premium or a symmetric/double-sided CfD.

(Double-sided) CfDs allow for high risk hedging but imply low market integration incentives, since they shield project developers from volatile wholesale prices by offering a guaranteed price level. When implementing CfDs, attention needs to be paid to the exact design to avoid an inefficient dispatch of OWPs. Under an (asymmetric/one-sided) sliding premium, generators are free to decide to bid on a (positive) price below their generation costs, which then effectively function as a floor price, and expect additional market revenues on top of the support payment or, in case of zero bids, rely on market revenues alone. The degree to which market revenue risks can be taken over by project developers are signalled by submitted bid prices and reflected in auction results. This flexibility to consider uncertain market revenues in their bid by increasingly lowering their bid price is the key advantage of a one-sided premium compared to a double-sided CfD. One-sided sliding premiums allow for a gradual evolution towards greater market integration, while under a double-sided CfD entailing a payback requirement, bidders are incentivised to bid a fully cost-reflective bid and thus market price risks remain with the society rather than project developers.

These recommendations do not necessarily reflect national policy preferences, national support scheme legacies, inherent support scheme logics (also across technologies), or existing path-dependencies. These aspects are relevant for Member States and we recommend maintaining this flexibility for Member States. In addition, when cooperating, Member States have to agree on whether to provide support for an OWP and in what form. Given the different support scheme legacies and current schemes (e.g. hourly symmetric CfD in UK, yearly symmetric CfD in DK, multi-criteria assessment in NL and asymmetric sliding premium in Germany), cooperation will require substantial flexibility by the involved Member States to agree on a common support scheme design for cooperation projects (or to apply one of the existing ones).

3.1.4.4 Tender design

Building on the lessons learned in task 1, this section provides recommendations on a suitable tender design for the generation component of hybrid offshore projects that can be applied in various project contexts such as those outlined in section 3.1.3.

While the cross-border nature of hybrid offshore projects is one of their defining characteristics, in most project setups this primarily relates to the transnational infrastructure component (i.e. interconnector) of the hybrid project rather than the generation asset. Support to OWPs forming part of a hybrid offshore project is likely to be tendered as part of single-item, site-specific auctions. These auctions differ substantially from typical cross-border auctions for other technologies (e.g. the joint solar PV auctions between Denmark and Germany), which are usually multi-item auctions and imply cross-border competition between multiple sites. Due to the lack of competition between sites across countries, the design of auctions for the generation component of hybrid offshore projects will arguably be less affected by hybrid project's cross-border nature as a result (assuming single-item, site-specific tenders).

The design of tenders may relate to the project setups (see section 1.1), where countries cooperate by establishing a joint support scheme that is used to jointly tender support to different OWPs connected to an interconnector (Case 5 – Multi-project hybrid offshore cooperation) or where each country uses its existing tender scheme for OWP located in their respective territory (Cases 1 to 4). For hybrid projects (Case 3 and 4), this may imply different auction designs within one bidding zone. For case 5, we assume that countries would set up a new joint support scheme under which site-specific tenders for OWPs located in different countries and connected to an interconnector would be organised. This likely implies a common (or at least similar) tender design for each of the site-specific tenders organised under this joint support scheme.

When countries tender support individually to OWPs located on their territory, the advisable tender design is unlikely to differ substantially compared to national offshore wind auctions, as each country can in principle set its own tender rules for the allocation of support to the respective OWP to be connected to the overall hybrid project. In the case of hybrid projects, the main aspect to consider is the necessary coordination between countries in terms of an adequate sequencing of the required transmission infrastructure/interconnectors to realise the overall hybrid project in time and avoid resulting project realisation delays of awarded OWPs (see also section 3.4). Moreover, assuming site-specific tenders combined with a central site selection model, the relevance of certain elements such as material pre-qualification requirements is lower, as the pre-development of the project is (partly) taken over by public authorities instead of project developers.

In case countries jointly tender support via site-specific tenders under a joint support scheme (Case 5), certain auction design elements may have to account for the national contexts of all involved cooperation countries. This highlights the importance of setting realistic realisation periods for cross-border offshore hybrid projects. At the same time, varying national framework conditions outside the auction design, such as the applicable grid connection regime or varying site development procedures, may be more relevant in this context. In addition, the adequate sequencing of the realisation periods of different project components becomes particularly important if the project is complex and spans across multiple countries, since a delay in one component may cause the further delay of other project(s)/project components. Many design elements are less or not at all affected by the cross-border nature of hybrid projects (e.g. the suitability of the tender procedure and pricing rule).

Independent of the specific cooperation model, good practices of auction design, such as ensuring sufficient competition between and mitigating excessive risks for bidders, also apply in the case of (cross-border) hybrid offshore projects. The following basic tender design principles (based on the AURES project[234]) should be considered where auctions are applied across borders or where support is paid across borders:

- **Adapt design to (hybrid) context:** In case of a multi-project hybrid offshore cooperation including a joint support scheme (Case 5), the auction design should consider the increased coordination requirements between different actors, e.g. TSOs and project developers. Realisation deadlines need to be realistic and technical requirements may have to be aligned. In case multiple OWPs in various EEZs are subject to their respective host country support schemes (Cases 3 and 4), support schemes and tender design should be aligned as much as possible.
- **Keep it as simple as possible:** Design choices that increase complexity should be avoided. For tenders for hybrid offshore projects, market participants already may need to become familiar with new/different auction setups and might have alternative auctions schemes to participate in (even though offshore bidders are typically big players that are used to different designs in different countries). For example, for more complex hybrid project setups involving multiple OWP in various countries, it may be advisable to tender individual OWP rather than the whole hybrid project.

[234] For more information on best practice auction design principles, see **aures**project.eu and **aures**2project.eu

- **Give sufficient consultation and bid preparation time:** To attract a large number of market actors, potential auction participants need to be given sufficient time for consultation and bid preparation to become familiar with and adapt to a new auction design and procedure, also with information in all languages of the participating countries.

In the following paragraphs, we assess relevant tender design elements for the allocation of support to the OWP component of hybrid offshore assets.

Auctions vs. negotiated tenders

The allocation process for offshore wind support can follow a competitive auction or a negotiated tender. In negotiated tenders, power producers and the government can negotiate the technical and commercial terms of the project after an initial bidding stage. An auction is a competitive bidding process for allocating support to renewable energy producers. It is designed to allocate a support contract based solely on the bids submitted by participating bidders according to transparent award rules. There is no negotiation after the bidding concludes.

Among NSEC countries there is a clear trend towards auctioning support for offshore wind, partly as a result of the EU Guidelines on State Aid for Environmental Protection and Energy (EEAG) mandate for energy subsidies to be granted through competitive bidding processes from 2017 onwards.[235] However, in some NSEC countries a negotiated tender is still adopted, like the Dunkirk tender in France and the upcoming Thor tender in Denmark. In Denmark, preliminary bids are followed by a negotiation round with the Danish Energy Agency to finalise the tender specifications.[236]

Assessment for hybrid offshore projects

Given the inherent legal and technical complexity of hybrid offshore projects, a negotiated approach may help to avoid unintended participation barriers and risks for developers by granting project developers (and public authorities) the flexibility to adapt technical and commercial projects terms after the initial bidding stage. This may be particularly relevant in contexts where the project scope and technical requirements are not fully defined from the outset and the overall project setup is complex. At the same time, a fully negotiated and potentially non-competitive allocation mechanism may face legal challenges in terms of its compatibility with the EEAG. To ensure state aid approval by the European Commission, a negotiated allocation process would have to entail certain competitive elements (i.e. selection of awards based on objective criteria) and negotiation should be limited to a defined and restricted scope.

While negotiated tenders give the government and bidders more flexibility to influence tender requirements and tailor the offshore project (e.g. in terms of project size and price), auctions provide significant benefits compared to an allocation mechanism involving negotiations between the buyer (the government) and the seller (producer). Where auctions are feasible (e.g. in case of a clearly defined project setup and technical implementation requirements), they are generally advisable compared to negotiated tenders.

Auctions result in stronger competitive price building due to the absence of a post-bidding negotiation stage present in negotiated procurement, such as bilateral negotiations. Given that offshore project developers are usually larger actors able to bear these competitive pressures, the resulting price reductions observed in many markets can positively influence support cost reductions and also indicate a capability on the side of bidders to deal with the general risks of auctions (e.g. not being awarded). The potential risks of the winner's curse and of limited competition in auctions need to be

[235] Communication from the Commission, 2014. Guidelines on State aid for environmental protection and energy 2014-2020 (2014/C 200/01).
https://eur-lex.europa.eu/legal content/EN/TXT/?uri=CELEX%3A52014XC0628%2801%29

[236] EWEA, 2015. Design options for wind energy tenders.
https://www.ewea.org/fileadmin/files/library/publications/position-papers/EWEA-Design-options-for-wind-energy-tenders.pdf; DEA, 2019. New Danish calls for offshore wind farm tenders.
https://ens.dk/sites/ens.dk/files/Vindenergi/offshore_wind_tendet_thor_marketing.pdf

adequately considered in the tender design; however, to ensure the effectiveness (i.e. high project realisation rates) and efficiency (i.e. cost-reflective bid prices) of auction results.

Project execution after contract award is usually faster in auctions than in negotiated procurement, in particular due to the absence of a negotiation stage in auctions. Assuming no delays in the implementation of the auction, project execution can continue after bids are selected and awarded. In a negotiated tender, project execution can only begin once the negotiation with preferred bidders concludes and contracts are awarded. The reduced transaction costs for involved actors and potentially lower delivery times for projects speak to the implementation of auctions rather than a negotiated procurement process. Moreover, a protracted negotiation stage can lead to prices that are no longer reflective of market conditions once the implementation starts. This is particularly relevant for offshore wind projects where lead times are already significantly higher than for other renewable energy projects increasing uncertainties related to the developments of technology and market prices.

Auctions offer higher levels of transparency in the selection process compared to a negotiated procurement. The existence of formal participation and award criteria reduce the room for discretionary judgment calls in the procurement process. Requirements tend to be publicly posted or disseminated among bidders and can include bidder requirements (financial and technical capability to execute similar projects), and financial guarantees (bid and performance bonds). Ensuring that the same information and clarifications are accessible to all bidders increases the transparency and fairness of the auction process. This advantage of auctions equally applies for all renewable energy projects, including hybrid offshore projects.

Innovation requirements

Tenders may include non-price award criteria to value innovation in bids. For example, in the Hollandse Kust (noord) IV Dutch tender, developers are scored on their demonstration of innovation and knowledge sharing. An additional point of attention is the multi-use of offshore zones[237] between offshore wind development and fishing or Natura 2000 areas. Alignment between respective countries on possible multi-use of the offshore area and linking this to innovation requirements or scoring criteria could help foster cross-sectoral initiatives that optimise the use of the offshore area. When setting additional qualitative criteria beyond price, the effects this may have on bid prices should be considered, i.e. potentially higher bid prices due to increased requirements for bidders.

Assessment for hybrid offshore projects

Innovation requirements related to the multi-use of land could be relevant for hybrid projects, which might require larger available clustered areas for offshore wind farms. By scoring innovation in these tenders, cross-sectoral developments could be accelerated such as the inclusion of offshore technologies that are not yet competitive in the market, new technical grid solutions, or coupling with storage or power-to-gas.

Technology-specific or multi-technology process

Support can be auctioned for offshore wind technology and even for specific offshore wind sites. In contrast, offshore wind farms could compete with other technologies in a multi-technology or technology-neutral auction. Nearly all NSEC countries have implemented technology-specific and even site-specific (for countries with centralised site selection) auctions for offshore wind, with the UK conducting grouped/multi-technology auctions for less mature technologies in which offshore wind can participate. This means that in the UK offshore wind competes with other emerging renewable technologies, such as anaerobic digestion, wave, and tidal. In a technology-neutral auction, offshore wind would have to compete with all renewable energy technologies, including more mature onshore technologies.

[237] WindEurope, 2019. Our energy, our future How offshore wind will help Europe go carbon-neutral. https://windeurope.org/wp-content/uploads/files/about-wind/reports/WindEurope-Our-Energy-Our-Future.pdf

Table 3-7 summarises the advantages and disadvantages of each approach.

Most NSEC countries see a degree of technology discrimination as beneficial to adapt the support scheme design to the particularities of offshore wind and avoid windfall profits for mature technologies. Moreover, technology-specific support provides the technology the chance for further maturing and creates economy of scale effects, becoming more competitive or even cheaper than more mature technologies in the future. Recent auction results show that there is sufficient competition in the North Sea region to place competitive pressure on support levels that reflect technology learning curves and maturity (see Figure 2-3).

For floating offshore wind projects, currently only pilot projects exist in the NSEC countries with dedicated funding. For future larger floating offshore wind projects two trends can be seen in the NSEC countries and the UK. In some countries, floating offshore wind could participate in technology neutral auctions or in dedicated pots for emerging technologies with dedicated minimum capacity caps for new technologies including floating wind, such as in the UK. In the UK, the revision for AR 4 plans to introduce floating offshore wind as a separate eligible technology with its own administrative strike price, providing a distinction from fixed-bottom projects. The latter would no longer be considered an emerging technology. Other countries are planning dedicated, site-specific floating offshore wind tenders, such as France (see section 2.1.3.3).

Table 3-7. Advantages and disadvantages of technologies included in the auction.[238]

	Technology-/site-specific	Multi-technology/ technology-neutral
Advantages	Low risk of sunk costs of stranded assets for sites pre-developed by a state body. Allows for development of strategic sites.	Competition with different RES technologies increases competitive cost pressure. Allows most cost-competitive sites to be developed first.
Disadvantages	Potential higher cost to consumers for RES support if emerging technologies or strategic projects are supported.	Prevent strategic or emerging technologies to mature, as they will have difficulty to compete with already more matured renewable technologies in the short term. Potential windfall profits for mature technologies.

Assessment for hybrid offshore projects

Offshore wind sites that will be part of hybrid projects would benefit from technology and site-specific auctions as these projects would be highly strategic but probably not directly competitive with conventional offshore or onshore projects in the short term. These wind farms would be potentially located further offshore, increasing technical implementation challenges. This introduces a risk that hybrid projects are not competitive with other mature technologies on a project-basis. When adopting a site-specific process, it is important to ensure sufficient competition between interested developers.

Tender procedure and pricing rule

The organisation of tenders should fulfil three general principles: the submitted bids are binding, the bidders with the best bids win, and the winning bidders receive at least their bid price. The two fundamental tender types are static and dynamic auctions, both of which fulfil these criteria and have

[238] IEA RETD, 2017. Comparative Analysis of International Offshore Wind Energy Development. http://iea-retd.org/wp-content/uploads/2017/03/IEA-RETD-REWind-Offshore-report.pdf

been used in renewable energy auctions. In principle, each of these types can be further segmented by their payment rule, which is either discriminatory (i.e. pay-as-bid) or has uniform prices (i.e. uniform pricing, pay-as-clear).

The most common tender formats for RES are static or sealed-bid tenders, i.e. all bidders simultaneously submit their bids and bid prices are unknown to all other bidders. This tender format is called static as all bids are submitted only once, making it impossible for competitors to react to other bid decisions. Hence, bidders only learn their competitors' bid prices after the auction has ended and they do not receive the option to adapt their bids. Most NSEC countries have adopted static auctions.

Static tenders can have different pricing rules, i.e. pay-as-bid tenders or uniform-price auctions. In a pay-as-bid tender, winners receive their offer price (also known as a discriminatory price auction). In a uniform-price tender, winners receive the market clearing price (also called pay-as-clear auction). Since tenders for offshore hybrid projects are likely to be conducted as site- and project-specific tenders for individual OWP—i.e. only one auction winner and only one strike price emerges from the auction—the differentiation between pay-as-bid and uniform pricing will usually be less relevant. This report does not discuss the pros and cons of the different pricing rules in detail.

In contrast to the sealed-bid one-shot situation in static tenders*,* dynamic tenders offer bidders the opportunity to observe the development of the auction price and other bidders' bids during several phases and to adapt their bidding strategies during the tender process. In a dynamic, open tender procedure, the auctioneer decreases the price continuously within predefined fractions of time across the different tender phases and bidders signal successively their acceptance of the recent price until only one bidder is willing to accept the price (i.e. descending clock auction). In the case of a site-specific hybrid offshore wind auction, the bidder accepting the lowest support level is awarded. Dynamic auctions are only adopted in the Danish nearshore tenders.

To allow for differentiation in case of zero bids, dynamic auctions may be suitable to determine the size of an additional concession payment, i.e. the last bidder willing to accept the highest concession payment will be awarded. An ascending clock auction for the determination of a second bidding component has been proposed for future offshore wind auctions in Germany, but it remains to be seen whether it will be adopted by Parliament.

Assessment for hybrid offshore projects

Static or dynamic auctions may be used for hybrid offshore projects. If the goal is to select a tender format that leads to efficient tender results and minimises transaction costs for all parties involved, static auctions can be used. At the same time, the higher transaction cost for dynamic tenders compared to static tenders are less important in the case of hybrid offshore, given the large investment volumes involved and the likely participation of larger actors able to bear such costs. Moreover, the often-stated higher risk of collusion between bidders in the case of dynamic auctions (since participants are able to use bidding to signal or communicate) mainly relates to the existence of multi-project bidders and is thus less relevant in the case of site-specific auctions for hybrid offshore projects. Hence, in particular for projects with higher technology and revenue risk (e.g. OWP further offshore, floating offshore), dynamic auctions may be used to promote the sharing of information among bidders in the bidding stage (e.g. on expected market values). Since bidders can correct their initial bid in the process, this decreases the risk of the winner's curse.

Pre-qualification requirements

Pre-qualification requirements are implemented to increase the probability of timely project realisation and to ensure the seriousness of bids to prevent bidders from participating in a tender with no serious intent to realise the project. Ensuring timely project completion of these projects through adequate pre-qualification requirements should be considered given the technical and regulatory complexity, the financial scope and strategic value of hybrid offshore projects, and the ambitious offshore wind deployment targets on national and European level. There are three types of pre-qualification requirements: material, financial, and bidder qualification requirements.

Material pre-qualification requirements

Material pre-qualification requirements (also called technical requirements) entail standardised proof of project progress, such as an environmental permit, an approved zoning or development plan or a grid connection agreement. Since awarded projects have already overcome some of the risks related to project planning, their probability to be realised increases. Technical requirements can help bidders submit more realistic prices in their bids as they gain information on site conditions, costs, and the potential effect of environmental regulations on project revenues—lowering the risk of underbidding. However, technical requirements occur as a sunk cost for the bidder because they are not reimbursed if the project is not awarded. This results in additional risks for the bidder and may create barriers for participation and lower competition. Technical requirements need to be realistic; a balance must be struck between strictness of requirements, appropriate levels of competition, and realisation rates.

Where sites are determined and pre-developed centrally by public authorities rather than project developers (which is the likely case for large-scale offshore hybrid projects), the relevance of material pre-qualification requirements to be submitted by bidders before entering the auction is usually less relevant. In these cases, the pre-development of the project is (partly) taken over by public authorities instead of project developers. Many NSEC countries have opted for the sole use of financial pre-qualification criteria (e.g. Denmark, Germany, and the Netherlands) or bidder qualification requirements (e.g. France). Only the UK makes use of various technical pre-qualification requirements (e.g. planning authorisations and lease agreements for the site), given its decentralised system of site selection.

Bidder qualification requirements are another type of pre-qualification requirement that ensure that bidding companies have sufficient financial or technical capacity. They refer to the documentation that needs to be provided by the company intending to participate in the auction and provide evidence that the bidder has sufficient capacity to develop the project. By pre-selecting bidders that meet the technical and financial requirements, submitted bids are reduced to the most promising ones. Bidder qualification requirements include legal requirements, proof of financial health, agreements and partnerships documenting third-party involvement in the project, and past experiences with references.

Financial pre-qualification requirements

Financial pre-qualification requires bidders to present a financial guarantee when entering the tender and/or upon being awarded a bid. This can be done through bank guarantees or a cash deposit in a designated bank account. Financial guarantees are usually linked to penalties, as the guarantees can be confiscated in case the bidder does not live up to its contractual liabilities, e.g. in terms of realising the project within the agreed realisation period.

Financial guarantees usually relate to the bid submission (i.e., bid bond) or the implementation phase (i.e., completion and performance bonds). Bid bonds aim to ensure the successful bidder's commitment to enter a contract after being awarded. If a successful bidder does not sign the awarded contract, the bid bond will be retained by the auctioneer. Performance and completion bonds protect the buyer against project delays, noncompletion, and underperformance during the operation phase. A completion bond will be retained for the benefit of the auctioneer if an awarded project is not commissioned by the agreed commercial operations date; otherwise, the bond is paid back to the bidder. A performance bond may also be defined to ensure the commissioned project meets energy generation and technical performance criteria.

Assessment for hybrid offshore projects

Hybrid offshore projects are strategic projects that will contribute to accelerating offshore wind generation capacity development and interconnectivity between countries. Given their technical and regulatory complexity and the ambitious offshore wind deployment targets on national and European level, the timely implementation of these projects is of high importance. In principle, pre-qualification requirements should be included in the tender design for hybrid projects to ensure only serious bids are considered and preventing compromised realisation timelines. When setting pre-qualification requirements, the right balance between setting an adequate incentive to realise the project and limiting excessive risks for project developers should be achieved. Otherwise, competition levels may be adversely affected, especially considering the innovative and emerging (i.e. already higher risk) nature of hybrid projects.

International experience suggests that adequate material pre-qualifications and bidder qualification requirements are generally an important safeguard for successful project realisation.

Bidder qualification requirements may be particularly suitable for hybrid projects given their large technical and regulatory complexity and financial scale and the necessity to ensure the bidder's financial and technical capacity to implement the project. In a joint support scheme between multiple countries (Case 5), all required documentation should be provided by each prospective bidder, independent of where the project is located.

Material pre-qualifications are only relevant in case project developers have certain responsibilities for the pre-development of an awarded OWP as part of a more decentralised system to provide proof of project progress. Should material pre-qualification requirements be implemented (i.e. in case project development is more decentralised), the cross-border context of tenders for certain hybrid offshore project setups should be considered. For example, a multi-project hybrid offshore cooperation (Case 5), where different OWP located in different countries are connected to a common interconnector subject to a new joint support scheme, could imply that the same or at least similar tender rules would be applied to various site-specific auctions for OWP located in different hosting countries and potentially different national framework conditions.

Financial guarantees come with several advantages in the context of tenders for offshore hybrid projects (beyond the fact that material pre-qualifications are less relevant in the case of a centralised site selection and pre-development). First, they are less prone to be adversely affected by different national framework conditions such as permitting procedures and are more comparable across participating countries, which could become an issue in joint support schemes (Case 5). Moreover, they reduce administrative burden for the auctioneer compared to material pre-qualifications, since the latter usually require a more in-depth compliance check. To increase the probability of project realisation and ensure the seriousness of bids, the sole use of financial guarantees (both bid and completion bonds) will be advisable in most tenders for hybrid offshore projects, especially considering that most tenders will likely be specific to sites subject to a central model of site selection and pre-investigation.

Realisation periods

The realisation period specifies the time during which projects need to be commissioned (the validity of the award or time between award and commissioning). Penalties can be imposed if the realisation period is exceeded, i.e. if a project fails to be completed in time. Excessively long realisation deadlines are undesirable because they encourage speculative bids (e.g. developers speculating on equipment costs to fall or electricity prices to rise). Nonetheless, they should allow for project completion times that are realistic for the local market and the project delivery periods for the technology in question.[239]

Assessment for hybrid offshore projects

Realisation periods for hybrid offshore projects need to reflect realistic project delivery periods, especially given their strategic and innovative nature, while avoiding too long realisation periods that encourage speculative behaviour and thus increase the risks that projects are not realised. For offshore wind, the realisation period is usually several years (e.g. 5 years in the Netherlands) in line with longer project development cycles compared to other renewable energy technologies. For hybrid offshore projects, realistic project development cycles may vary under different project setups

[239] In the context of COVID-19, there have been disruptions in global supply chains and delays in national permitting procedures, both endangering timely project realisation and resulting in increased penalty risks. As an immediate response, several EU Member States have extended the realisation deadlines for RES projects (including for instance Germany, France, and Greece).

compared to non-hybrid offshore projects or may be subject to uncertainties given the interdependency with large cross-border infrastructure assets (interconnection) that have multiannual development periods. Delivery periods should align and coordinate with the required infrastructure development in terms of an adequate sequencing of the required transmission infrastructure/ interconnectors to realise the overall hybrid project in time and avoid resulting project realisation delays of awarded OWPs. When setting realisation periods, these considerations should be considered by adapting realisation periods to the specific hybrid project in question and/or providing prudent flexibility/margins for contractual delivery periods to account for the innovativeness and infrastructure requirements of these projects.

In the case of a joint support scheme between multiple countries (Case 5), varying framework conditions potentially leading to diverging realisation periods should be considered. Setting country- or even OWP-specific realisation periods may be useful to address differing local conditions (e.g. regulatory framework, depth of seabed) that inevitably impact realisation periods. At the same time, too much variation in realisation periods should be avoided to ensure transparency, allow for a coordinated and timely overall realisation of the hybrid project, and to incentivise an alignment and coordination of national framework conditions in line with best practices.

Penalties

Penalties are sanctions that aim to reduce the possibility of delays, underperformance, and project failures by increasing bidders’ costs of noncompliance with contractual obligations. They also reduce incentives for underbidding by pushing bidders towards more cost-reflective bids. International experiences show that in the absence of sufficient penalties, the risk of delays and project nonrealisation is higher. Besides the full or partial confiscation of financial guarantees if the bidder does not fulfil its contractual obligations, penalties may include the termination of contracts, exclusion of the bidder from future rounds, or a reduction in the remuneration period or level. Penalties may also be escalated over time to account for the extent of delays or deviation from contractual obligations.

All existing auction-based offshore wind support schemes in NSEC countries and the UK adopt some form of penalties, for example:

- Confiscating (fully or partially) of financial guarantees/bid bonds (e.g. Germany, the Netherlands)
- Terminating contracts and nonparticipation in future auction rounds (e.g. UK)
- Lowering support levels (e.g. Denmark)
- Shortening contract validity periods (e.g. France)

Assessment for hybrid offshore projects

Hybrid projects help accelerate offshore wind generation capacity and interconnectivity between countries, so their timely delivery is highly important. Combined with adequate pre-qualification requirements, this can be enforced through an appropriate penalty scheme for delayed and non-delivery of the project coupled with a specific project realisation timeframe, e.g. 5 years from the award of support. (Post-award) financial guarantees and the associated penalties in case of non-delivery or delay beyond the contractually agreed realisation period are a suitable option in this case. Such financial guarantees are linked to penalties and can be confiscated if the bidder does not fulfil its contractual requirements.

When determining the extent of penalties, the right balance needs to be struck between maximising realisation rates and avoiding excessive risks for project developers leading to low participation. If penalties are too low, this might lead to lower realisation rates. If penalties are too strict, this may lead to substantial risks for bidders resulting in low participation and higher bid prices. For hybrid OWP, coordination risks may be higher compared to other renewable energy projects as a result of the increased complexity and involvement of various actors (e.g. TSOs, Member States, private developers). Higher penalties may add to these potential risks project developers face. At the same time, ensuring high realisation rates by ensuring only serious bids are considered is key in the context of large-scale (hybrid) OWP. Implementing sufficiently high penalties decreases the winner's curse risk and ensures that bidders submit adequate bids that are likely to allow for successful project completion. In line with international best practices, imposing financial guarantees in the range of up to 10% of estimated project costs may be suitable to ensure project delivery. However, this only serves as a rough indication and should be flexibly adapted to the context of specific tender rounds and tendered project setups.

3.1.5 Impacts of including storage and PtX into the project setup

This section discusses the circumstances under which the development of local storage or PtX facilities have a direct impact on the operation of the OWP. Project configurations for a joint support and tendering of OWP and storage/PtX facilities (i.e. an integrated project setup) are also considered. For this case, implications on the design of support schemes and tenders are presented.

Storage and PtX technologies such as hydrogen are set to play an important role in decarbonising the future energy system. Their combination with the use of offshore wind power is increasingly discussed as they have the potential to support the integration of large volumes of offshore wind power.[240] Potential benefits of using parts of the North Sea offshore wind power for PtX solutions, such as (offshore) hydrogen production, are reduced need of offshore and onshore transmission capacity and reduced congestion in the transmission system. By increasing the demand for offshore wind power and shifting parts of the offshore wind power to periods with higher prices on wholesale markets, PtX and storage technologies may improve the business case for offshore wind. At the same time, storage and PtX technologies are associated with significant costs (both CAPEX and OPEX) making additional financing necessary to enable their market launch and scale up.

Combining offshore wind power with storage or PtX technologies has the potential to change the entire project setup significantly by impacting the infrastructure costs, the need for connection and transmission capacities, the flow of electricity to the connected market areas, and the need for support payments. The magnitude of impacts on the OWP (and hence the necessity to account for those in the support scheme and tender design) strongly depend on how the offshore wind assets are combined with the storage/PtX assets in terms of technical aspects, most importantly the grid connection of the storage/PtX assets (direct connection to the OWP or connection to the grid) and their positioning (onshore or offshore).

The possible combinations of OWP with storage/PtX and the options of financing storage/PtX are numerous. For many of these project configurations, integrating the OWP and the storage/PtX facilities in one project setup is not an option. In those cases, the direct impact on the operation of the OWP and of the storage/PtX assets is limited, while a positive effect for the integration of the offshore wind power into the system still occurs. In the following sections we present the potential project configurations for storage/PtX combined with offshore wind energy. We use hydrogen production as an exemplary technology to illustrate possible combinations of OWP with storage and PtX technologies. In addition, we describe some of the fundamental options of supporting hydrogen (H_2) production. The implications of an integrated project setup (i.e. the OWP and the H_2 facility integrated into one project) on the support for the project largely depend on the general support framework and market context for H_2.

We conclude with the case of an integrated project setup, describing the basic design options of incentivising hydrogen production, providing stable revenues to the project, and detailing implications for the tender design.

[240] For example, the joint declaration of the North Seas Countries and the European Commission from July 2020 emphasises the potential and importance of an offshore wind-hydrogen nexus for the future energy system. See: https://www.bmwi.de/Redaktion/EN/Downloads/M-O/nsec-joint-statement.pdf?__blob=publicationFile&v=2

3.1.5.1 Potential project configurations

There are two decisive aspects regarding the technical configuration of combining H_2 production with offshore wind energy: 1) the positioning of the electrolyser (onshore or offshore), and 2) the connection of the electrolyser (on-grid vs. off-grid) and the electricity is consumes.

1) Hydrogen production - offshore vs. onshore:

Hydrogen production combined with offshore wind energy can be done onshore or offshore. When producing hydrogen offshore several options exist for the placement of the electrolysers, including existing gas or oil platforms, dedicated new platforms or artificial islands, and in or on (e.g. on the gallery of) wind turbines.

The major advantages of installing electrolysers offshore are:

- Potential overall cost advantages compared to onshore hydrogen production mainly due to lower costs for offshore electricity transmission infrastructure as not all harvested wind energy has to be transported to the shore via electricity transmission cables. Analysis shows that this is especially the case when OWP are located far offshore (>80 km), meaning expensive HVDC technology would be required for onshore grid connection, and existing (retrofitted) offshore gas infrastructure can be used.[241,242,243]

- Electrolysers installed close to the intermittent renewable energy source (the OWP). This avoids transport losses and helps stabilise the offshore electricity transmission grid, which reduces the need for expensive electricity transmission infrastructure offshore and onshore.

- Eventually less public resistance due to lower spatial impact at shore and security concerns.

Disadvantages for producing hydrogen offshore are:

- Electrolysers are operated in a more challenging environment.

- High investment costs for electrolysers platforms that do not occur for onshore hydrogen production.

- Retrofitting of existing gas infrastructure or new dedicated hydrogen pipelines required.

- Space constraints exist for existing oil or gas platforms (mother platforms can host approximately 250 MW and satellite platforms can host approximately 60 MW electrolyser capacity).[244]

- Seawater desalination plants are required to supply electrolysers.

- Additional infrastructure is required to enable the transport of other eventually produced chemicals, such as methanol, and the side products from the electrolysis process (oxygen, heat) to shore.

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[241] World Energy Council (2017): Bringing North Sea energy ashore efficiently. https://www.weltenergierat.de/wp-content/uploads/2018/03/Bringing-North-Sea-Energy-Ashore-Efficiently.pdf

[242] DNV GL, 2018. Power-to-Hydrogen IJmuiden Ver. https://www.tennet.eu/fileadmin/user_upload/Company/Publications/Technical_Publications/Dutch/P2H_IJmuiden_Ver_-_Final_Report_-_Public.pdf

[243] Jepma et al. (2018): North Sea Energy - D3.6 - Towards sustainable energy production on the North Sea - Green hydrogen production and CO2 storage: onshore or offshore?

[244] World Energy Council (2017): Bringing North Sea energy ashore efficiently. https://www.weltenergierat.de/wp-content/uploads/2018/03/Bringing-North-Sea-Energy-Ashore-Efficiently.pdf

When producing hydrogen onshore, electrolysers can be installed close to shore near the landing points of the offshore electricity transmission cables that connect the OWP with the onshore electricity transmission grid or deeper inland. Installing electrolysers close to the shore instead of deep inland is advantageous in that electrolysers can contribute significantly to the onshore grid integration challenge resulting from a large-scale deployment of offshore wind energy in the North Seas. Electrolysers at coastal regions can reduce grid congestion and curtailment of offshore wind energy significantly by converting electricity into hydrogen during periods when OWP generation exceeds the hosting capacity of the onshore electricity transmission grid. Therefore, the need for expanding the onshore transmission grid can be reduced.

2) Connection of electrolyser - on-grid vs. off-grid:

Several options exist to supply electrolysers with electricity. Electrolysers can be connected to the electricity grid (on-grid connection, onshore or offshore—#1 of Table 3-8) or supplied only by dedicated and directly connected power plants, i.e. OWP (off-grid connection, #2, 3 and 5, 6). A third alternative is that the electrolyser is supplied with electricity directly by the OWP through a dedicated transmission cable and additionally via the electricity grid (hybrid connection, #4, 7).

The way the electrolyser is connected has a strong impact on the electricity costs for and the FLH of the electrolyser. Both have a strong impact on hydrogen production costs as shown in Figure 3-3. In the case the electrolyser is connected to the electricity grid (on-grid, #1), annual full load hours are only limited due to planned and forced outages of the electrolyser. The same is the case for the hybrid connection approach (on-grid, #4, 7). In the off-grid connection approach (#2, 3 and 5, 6), the annual utilisation of the electrolyser is limited to the FLH of the OWP, which are in the range of 3,000–4,000 in the North Seas. In the on-grid approach, where the electrolyser consumes electricity only from the grid, the electricity costs equals the electricity price including all taxes and fees if no exemptions exists. In the off-grid approach, the electricity costs of the electrolyser depend on the LCOE of the OWP. For post-2030, LCOE for OWP are expected to be in the range of €35/MWh–€65/MWh.[245]

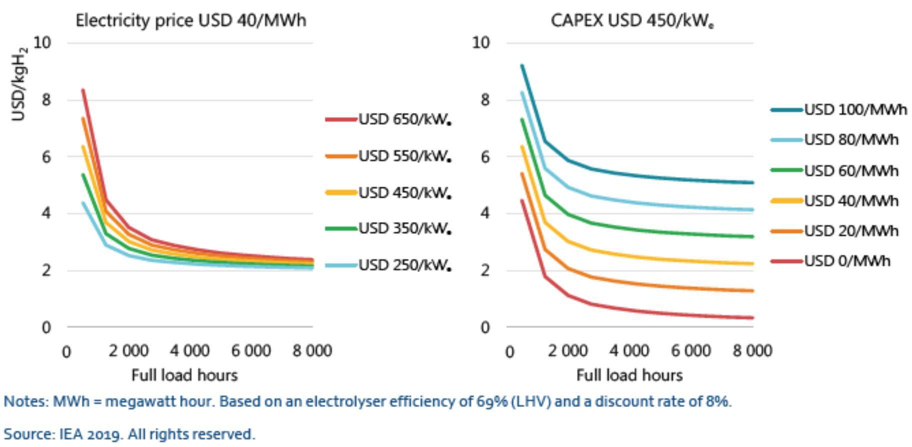


Figure 3-3. Future levelised cost of hydrogen production as function of FLH for different electrolyser investment costs (left) and electricity costs (right).[246]

As FLH of electrolyser increase, the impact of electrolyser investment costs on hydrogen production costs declines and impact of electricity costs increases. The impact of electrolyser investment costs on hydrogen production costs will decrease in the future due to expected reduction in electrolyser investment costs.

[245] Witteveen + Bos, 2019. Cost Evaluation of North Sea Offshore Wind Post 2030. https://northseawindpowerhub.eu/wp-content/uploads/2019/02/112522-19-001.830-rapd-report-Cost-Evaluation-of-North-Sea-Offshore-Wind....pdf

[246] IEA, 2019. The Future of Hydrogen - Seizing today's opportunities. https://www.iea.org/reports/the-future-of-hydrogen

The following subsections outline the basic options for H_2 project configurations in combination with non-hybrid OWP and hybrid OWP.[247] In terms of impacts on support scheme and tender design, there are no structural differences between combining H_2 with non-hybrid OWP compared to combining with a joint hybrid OWP. The latter case has implications on the allocation of costs and benefits between the connected countries, which is further discussed in section 3.2.3.2.

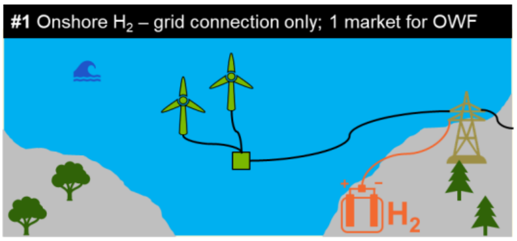
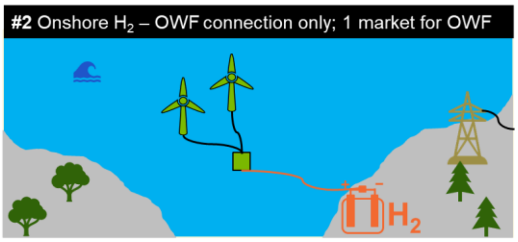
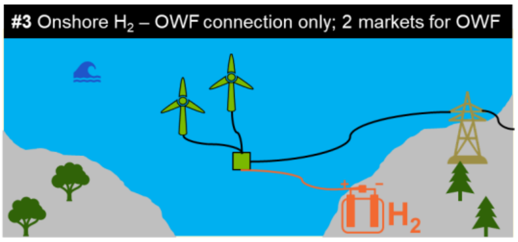
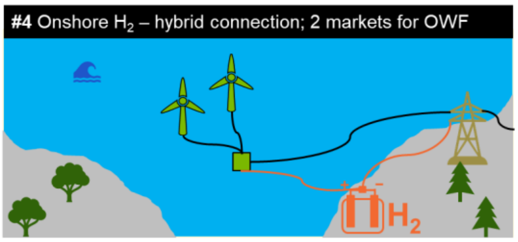
Basic options for project configurations in combination with non-hybrid OWPs

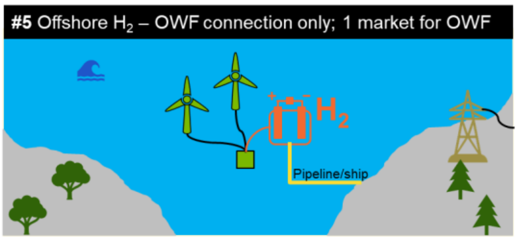
Table 3-8 shows seven potential project configurations for hydrogen production in combination with OWPs and summarises the advantages and disadvantages of the respective project configuration considering some general techno-economic aspects. In four of the seven configurations (#1-4), the electrolyser for hydrogen production is located onshore. In three cases, the electrolyser is located offshore next to the OWP (#5-7). In four cases (#2, 3 and 5, 6), the electrolyser is connected to the OWP only and cannot consume any electricity from the grid (off-grid). In the remaining three project configurations the electrolyser can consume electricity from the grid (on-grid) as the elctrolyser is connected to the electricity grid only (#1) or connected using an hybrid connection approach, i.e. a dedicated transmission cable between the OWP and the elecrolyser plus a connection of the electrolyser with the electricity grid (#4, 7).

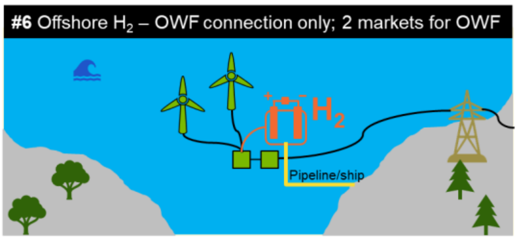
The presented project configurations for hydrogen production in combination with OWP can also be distinguished from the perspective of OWP project developers/owners. Depending on the project configuration, the OWP can participate on the electricity and hydrogen market (#3, 4 and 6, 7) or only on the electricity (#1) or hydrogen market (#2, 5).

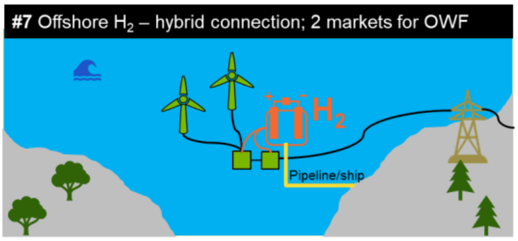
[247] The implications of different project configurations can be illustrated more easily when the additional layer of cross-border infrastructure and the implications of multiple market areas are not included, which is why we first show the combinations with non-hybrid OWF. Subsequently, combinations with cross-border hybrid OWF are illustrated.

Table 3-8. Overview of potential project configurations for hydrogen generation in combination with OWP

	Project configuration	Advantages and disadvantages
Onshore H_2 production		**Pros:** • Electrolyser capacity factor not limited to OWP availability • Electrolyser can support OWP onshore grid integration **Cons:** • Electrolyser operated with grid mix (renewable energy share?) • OWP can participate at power market only • Electrolyser pays full electricity price incl. taxes and fees if no exemptions exist
		**Pros:** • Electrolyser operated with 100% renewable energy • OWP has no impact on onshore electricity grid • Electricity costs for electrolyser equals electricity production costs of OWP **Cons:** • OWP and electrolyser capacity must be aligned • Electrolyser capacity factor limited to OWP availability • OWP can participate at H_2 market only
		**Pros:** • Same advantages as #2 • OWP can participate at electricity and H_2 market • OWP and electrolyser capacity must not be aligned **Cons:** • Electrolyser capacity factor limited to OWP availability • Additional infrastructure costs compared to #2
		**Pros:** • Electrolyser can operate with electricity from OWP and from the grid • Capacity factor of electrolyser not limited to OWP availability • Electrolyser can support OWP onshore grid integration • OWP can participate at electricity and H_2 market **Cons:** • Additional infrastructure costs compared to #1

<table>
<tr><th></th><th>Project configuration</th><th>Advantages and disadvantages</th></tr>
<tr><td rowspan="3">Offshore H_2 production</td><td>
</td><td>Pros:
• Same advantages as #2
• Less land use onshore
• Pot less electricity infrastructure costs than #2 especially when OWP located far from shore (>80 km) and existing gas pipelines could be used

Cons:
• Hydrogen production in challenging environment
• Desalination plant required
• OWP and electrolyser capacity must be aligned
• Electrolyser capacity factor limited to OWP availability
• OWP can participate at H_2 market only</td></tr>
<tr><td>
</td><td>Pros:
• Same advantages as #5
• OWP can participate at electricity and H_2 market
• OWP and electrolyser capacity must not be aligned

Cons:
• Hydrogen production in challenging environment
• Desalination plant required
• Electrolyser capacity factor limited to OWP availability
• Additional infrastructure costs compared to #5</td></tr>
<tr><td>
</td><td>Pros:
• Same advantages #4 and #6
• Only limited additional infrastructure costs compared to #6

Cons:
• Hydrogen production in challenging environment
• Desalination plant required</td></tr>
</table>

Which of the options illustrated above is the most sensible depends on the specific context. Some general basic considerations regarding the techno-economic aspects include the following:

Hydrogen production onshore: If the OWP is located far offshore, the project configuration #1 would be the most sensible configuration as all other configurations would lead to higher infrastructure costs and/or restrict the utilisation of the electrolyser. If the OWP is located nearshore, project configurations #3 and 4 might also be good options due to the fact that OWP operators could participate at multiple markets (electricity and hydrogen) and it could be tracked if electricity demand of the electrolyser is supplied by the OWP (100% from renewable energy) or via the electricity grid.

Hydrogen production offshore: Project configuration #7 has the most advantages, especially when the eletrolyser is in close proximity to the OWP. Project developers/owners of the OWP could participate at the electricity and hydrogen market and—due to the hybrid connection of the electrolyser—hydrogen production is not limited to the availability of offshore wind energy and it can be tracked if the electrolyser is operated by electricity provided by the OWP or by the electricity grid.

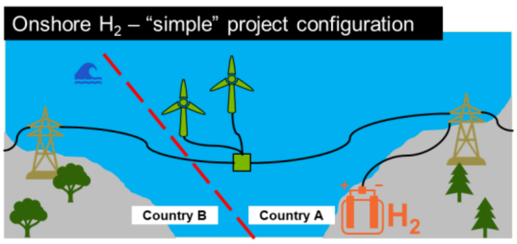
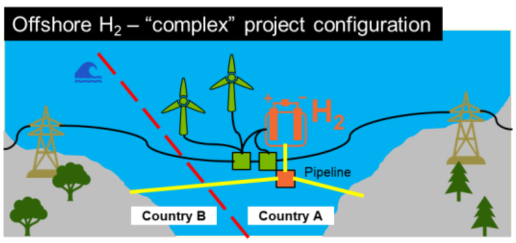
Furthermore, due to its connection to the electricity grid, the electrolyser could support the reliable grid operation offshore and onshore.

Basic options for project configurations in combination with hybrid OWP

Including hydrogen in hybrid projects increases the number of potential project configurations even further as, besides onshore/offshore and on-grid/off-grid, a third dimension is introduced: international cooperation. Hydrogen-related infrastructure could be involved only in a subset of the cooperating countries or in all involved countries.

Table 3-9 shows two potential project configurations for a hybrid project that involves hydrogen to illustrate the range of complexity. In a simple project configuration similar to #1, an electrolyser would be installed onshore and supplied with electricity via the electricity grid of Country A. The electricity transmission infrastructure that connects the electrolyser with the electricity grid of Country A would be the only additional infrastructure that would be included compared to the same hybrid project without hydrogen involved. A more complex project configuration would be where the electrolyser is installed offshore in the EEZ of Country A and is supplied with electricity mainly by the OWP next to it supplemented by the electricity grid. Similar to the electricity part, hydrogen transmission infrastructure in this project configuration has a dual-use purpose of connecting the electrolyser to the gas/hydrogen grid of Country A and interconnecting the gas/hydrogen markets of Country A and Country B. In such a project configuration, the costs and benefits associated with the hydrogen transmission infrastructure should be included in the CBA for hybrid projects as well.

Table 3-9. Two potential project configurations for hybrid projects that involve hydrogen

Project configuration	Description
	• Electrolyser installed onshore in Country A and connected only to the gas/hydrogen grid of Country A • Electrolyser only supplied via the electricity grid of Country A • Electricity and hydrogen transmission infrastructure required to connect electrolyser to the electricity grid and to the gas/hydrogen grid of Country A is the only additional required infrastructure compared to the same Hybrid Project without hydrogen involved • Costs and benefits of electrolyser (hydrogen production, supporting offshore wind energy grid integration, etc.) mainly for Country A
	• Electrolyser installed in EEZ of Country A and connected to the gas/hydrogen grid of Country A and Country B • Hybrid connection of electrolyser, supplied directly via the OWP and supplemented via the electricity grid • Gas/hydrogen transmission infrastructure for electrolyser grid connection (Country A) and for hydrogen market interconnection (with Country B) • Electricity transmission infrastructure to supply the electrolyser plus hydrogen transmission infrastructure to connect electrolyser to the gas/hydrogen grid and to interconnect hydrogen markets is additionally required compared to the same hybrid project without hydrogen involved

3.1.5.2 Basic options of supporting hydrogen production

The revenues from hydrogen fuel sales will not be enough to ensure economic feasibility of the production of green hydrogen. If the production of green hydrogen is not cost-competitive, support instruments are required to trigger investments in hydrogen facilities and/or hydrogen production.

Different instruments are being discussed to support hydrogen production. The most prominent and fundamental models are:

1) **Creating a market obligation based on a quota for (green) hydrogen:** A quota is a selective intervention in the market to support a certain technology. The quota obliges natural gas traders to reach a share green H_2 in their gas sales. Deviations in the physical delivery from the H_2 quota can be compensated by buying and selling H_2 certificates. This way, H_2 production is supported indirectly through a quota for (green) H_2. The quota results in a predictable demand for H_2, supporting a (market-based) price for H_2 and accelerating the technological learning curve.

2) **Upfront investment support for the electrolyser and hydrogen infrastructure:** Investment support entails a fixed upfront payment to the developer of the electrolyser which is related to installed capacity (i.e. a certain amount of € per kW). The grants provided lower the equity and debt required, also lowering the costs of debt, which increases the cost-effectiveness of the support. In principle, upfront investment support may be implemented without any additional (direct or indirect) operational support. However, depending on the costs of operation (i.e. mostly the costs of electricity), the provision of up-front investment support may not be sufficient to trigger investments in hydrogen production. Unlike a quota, up-front investment support can be implemented to selectively support individual projects. The selection of projects/operators can be done through an auction or can be based on specific criteria, for example, the (direct) use of electricity generated by an OWP.

3) **Direct operating support for hydrogen production:** Operating support can be designed to guarantee a certain minimum revenue per unit of hydrogen produced (e.g. a fixed premium is paid on top of the market price). The selection of projects/operators can be done through an auction.

4) **Exempting electricity used from taxes and levies:** The electricity input for green H_2 production could be exempted from taxes, levies and surcharges. Exemptions of any type of taxes, levies, and surcharges lower the costs of H_2 production and are a form of indirect operating support.

These instruments are not mutually exclusive but can be combined; several instruments may be implemented at the same time. For example, a Member State may implement upfront investment aid and exempt electricity is used to produce H_2 from taxes and levies to incentivise H_2 production.[248]

The conditions for investments in H_2 assets and the incentives that determine whether or not an H_2 asset is operating in a given situation will be shaped by the support instruments that are implemented, as well as by a multitude of further boundary conditions that determine the market environment, e.g. market prices for electricity and H_2, the occurrence of oversupply of electricity in the power system, and also the rules for the accounting of green H_2. A jointly tendered support of H_2 and OWP assets will need to be tailored to the broader policy context supporting H_2 production. However, this policy context that determines the general conditions under which investments and operation decision will be made in EU Member States is unknown today. Therefore, recommendations on designing the support scheme and tendering for integrated project setups can only be discussed at a high level.

[248] It is also being discussed whether H_2 assets can be owned and operated by TSOs. In that case, they would be classified as a network element and costs associated with the instalment and operation would typically be covered through grid fees, i.e. they would be passed on to electricity consumers and hence socialised.

3.1.5.3 Support scheme and tender design in case of an integrated project set up entailing both the OWP and the PtX facility

This section discusses basic options of providing support for an integrated project setup in which the OWP and the H_2 assets are jointly tendered. The main rationales for integrating the assets are based on the assumption that a project planner can optimise both assets better than separate actors, streamlining project development processes, improving the joint configuration and operation of the two assets, and reducing total investment costs. However, to what extent these efficiency gains materialise in practice is unclear.

The determining factor for a setup that integrates both the OWP and the H_2 assets in one project is the connection of the electrolyser. When the electrolyser purchases the electricity from the grid (and not from the OWP through a direct connection), it is an independent economic entity that acts as a normal consumer that purchases electricity at the market. Like for any other normal market actor, its electricity costs equal the electricity price including all taxes and fees if no exemptions exist. In that case, support for H_2 is separate from the support for the OWP and hence there is little reason of integrating the H_2 assets and the OWP in one project setup that is tendered jointly. However, if the electrolyser is directly connected to the OWP, integrating the H_2 assets and the OWP assets in one project setup (and jointly tendering the two) can be considered.

If the electrolyser is located offshore, a direct connection to the OWP is likely. However, as an offshore location entails higher costs, this may not be the most common option. From a cost perspective, there is much in favour of locating electrolysers onshore in coastal regions. In that case, a direct connection to the OWP is less likely, which makes an integrated project setup and a joint tendering of the OWP and the H_2 assets improbable.

Integrating support for the OWP and for H_2 is an option if there is a direct connection between the two. In that case, the following questions arise:

- What incentives and conditions for H_2 production should be implemented?
- Should support payments be made for the electricity output of the OWP only or also for the hydrogen production? If so, should support for H_2 be granted as operating or upfront investment support?
- Are the H_2 assets part of the technical requirements or a separate auction item?
- Should minimum requirements for operation of the H_2 assets be defined?
- How should support costs be recovered and who bears the costs?

The design of the specific support system has a strong influence on when H_2 is produced and when it is not. Therefore, it needs to reflect the general policy perspective on H_2 development and system optimisation. If the aim is to support the optimisation of the energy system, the direct use of electricity should generally be preferred, overusing the electricity output of the OWP to produce H_2 as the direct use of electricity is far more efficient. However, incentivising H_2 production beyond what is optimal from a system perspective also could be pursued to realise a market ramp-up of H_2 and provide a stable supply-base to potential industrial customers. In that case, the goal could be to maximise the H_2 production from a particular asset.

Options to implement the two different policy goals via the support instruments and tender design include the following.

Optimisation of the energy system: To provide for the instalment of a certain capacity of H_2 assets but also ensure that H_2 is produced only when this is considered optimal from the system perspective, the support may be limited to upfront investment support for a predefined H_2 production capacity. Such investment support would not influence the dispatch of the electrolyser, leaving it to market signals. Hence, OWP operators would decide based on market prices for H_2 and for electricity whether it is more beneficial to operate the electrolyser or to sell the electricity onshore. A disadvantage of this concept is that the market for H_2 is still immature and may provide distorted price signals. Such a market may not sufficiently reflect decarbonisation needs, which would justify additional operational requirements for the electrolysers (against this background, RED II introduces sustainability criteria for green H_2 and other RFNBOs used in the transport sector; however, these are not yet operationalised).

This approach could be reflected in the tender design of the integrated project by defining the obligation to install a certain amount of capacity of H_2 production in addition to the OWP as part of the technical requirements to be met by the project developer. Bidders could be requested to hand in a bid for the upfront investment support for the H_2 asset in addition to the bid for support for the OWP (if any). However, such a twofold bid would create challenges for the evaluations of bids. For example, to compare the twofold bids between bidders, a weighting of the two separate bid elements must be implemented to allow the selection of the best combined bid. Alternatively, the upfront investment support could be predefined by the auctioneer and hence be the same for all bidders. Bids would then only be compared based on the bid level for the electricity produced by the OWP.

A general challenge of the approach to require/incentivise the installation of H_2 assets but not establishing a dedicated incentive for the production of H_2 is that the bidders may place bids under the assumption of not producing any H_2 or installing cheap electrolysers of low (technological) standard.

Maximising H_2 production: Incentivising or requiring a high H_2 production seems questionable from a system perspective, as it favours the production of H_2 over the more efficient, direct use of RES electricity. It may still be suitable for an early market ramp-up phase of H_2, providing a stable supply-base to potential industrial customers. Several options to ensure high outputs of H2 are conceivable:

1. A regulatory requirement to operate the electrolyser at maximum capacity could be implemented without granting specific support for the H_2 production. In this case, only the power that is not consumed by the electrolyser is fed into the grid. This option would be suboptimal as electricity market prices are ignored in the operating decisions and electrolysers would be prevented from operating in a flexible manner.

2. Grant a higher level of support for the electricity of the OWP that is used to produce H_2 compared to the support for the electricity injected into the grid. Consequently, two separate support levels and support premiums are established. The effect of this is that the project operator will decide to switch from injecting electricity into the grid to H_2 production at a higher electricity price level.

3. Incentivise H_2 production is to implement an additional system of operating support directly for the H_2 production. For example, grant a premium for every qm of H_2. In that case, a fixed market premium is recommendable (i.e. a top up on the H_2 market price). The effects will be similar to option 2.

The second and the third option both require bidders to hand in a two separate bids, one for electricity injected into the grid and one for electricity used as input for H_2 production (second option) or for the H_2 premium (third option). This implies that a weighting of the two separate bids needs to be defined to rank the twofold bids from different bidders. Alternatively, the auctioneer may predefine the level of operating support that is directly related to the H_2 production.

If the goal is to guarantee a certain capacity of H_2 in addition to incentivising its production, the tender requirements should predefine the capacity of the H_2 facility as part of its technical requirements. In addition, defining a minimum volume of H_2 production or operating hours per year may be considered.

Central to the design of a support instrument for hydrogen is who will eventually bear the costs of support. Costs incurred by the support instrument can be passed on to the hydrogen end users, the taxpayers, or remain with the electricity sector if, for example, costs are passed to the levy payers of the existing RES support mechanisms. In principle, the costs associated with the production of H_2 should be borne by those actors that benefit from the supply, the end consumers of hydrogen, or by the sector where the hydrogen is used. In an integrated project setup, distinguishing between the costs of the OWP and the costs of the H_2 assets may not be straightforward. However, a distinction between the support costs associated with the electricity and the H_2 production can be made more easily if support payments are kept separate. This can be achieved by implementing upfront investment support for H_2 and/or an additional system of operating support directly for the H_2 production rather than reflecting the support needs for H_2 production in the support payments for the production of electricity. The support payments for H_2 may then be passed on to either the consumers of H_2 via a levy, or be covered by the state budget, i.e. the tax payers, while the support costs for the OWP remain in the electricity sector (depending on the system of cost recovery of the Member State).

3.1.5.4 Effects of an offshore PtX facility on trade flows and clearing price at an offshore hub under different market arrangement

Some of the project configurations discussed above are based on the idea of locating an electrolyser to produce hydrogen (or any other PtX facility) offshore, close to the OWP. This placement raises questions on the effects such a setup would have on the operation of the electrolyser, the trade flows between the connected market zones, and on the clearing price at an offshore hub. This section discusses the general effects of an electrolyser that operates at the same hub as the OWP and is connected in a way that allows it to source electricity either directly from the OWP or from the grid.

In the following, it is assumed that the electrolyser is an independent actor on the market, it bids a price at which it is willing to purchase electricity and adjusts its operation according to market prices. The electrolyser will only operate in situations when revenues are equal or higher to the cost of operation, when it is profitable. This is when the revenues of selling H_2 (market revenues plus support payments) are higher than the costs of producing H_2, which are largely determined by the power price. The power price at which H_2 starts to produce will depend on the revenues the operator can expect and so on the support scheme in place. In a HZ market arrangement, the power price for the electrolyser and the OWP are equal to the prices onshore. Locating the electrolyser offshore has the same impact on power prices as in a situation where the electrolyser is located onshore. In practice, this price effect may be little or zero, assuming that the electrolyser demand is small compared to the supply and demand in the HZ.

In an OBZ, price effects are more likely to occur. Assuming the power price is low enough to operate the electrolyser, demand is created offshore, which shifts the demand curve at the hub and impacts trade flows. This also affects the clearing price at the hub. Before getting into the details on potential price effects, it is important to reiterate how price formation at an OBZ works. The market clearing price in a bidding zone can be calculated as the (systemwide) marginal cost of supplying one additional megawatt of demand located in that bidding zone. Consequently, the clearing price in the OBZ will be equal to the highest price among the bidding zones to which there is no congestion (i.e. if the OWP would produce one more MWh, it could export this energy to that market zone). In many real-world cases with non-negative prices the resulting market price of the OBZ will be equal to the market price of the cheapest bidding zone it is connected to.

The demand created by an electrolyser’s operation can change the occurrence of congestion in the transmission lines connecting the hub with the other market areas. An interconnector that has no congestion and serves to evacuate offshore wind power to an onshore market area that is price-determining for the OBZ may become congested as a result of the changes in trade flows created by the demand of the electrolyser. The same is true the other way around. An interconnector that would otherwise be congested may not be congested anymore due to the increased offshore demand created by the electrolyser. In such a situation, the price at the hub will change to become equal to the price of the bidding zone to which there is no congestion. Both the electrolyser and the OWP will then face a higher power price. However, this effect only occurs if the electrolyser operation leads to a change in interconnector congestion. The likelihood of such an effect depends on the network typology (the relative scales of interconnector capacities), the electrolyser capacity, and offshore wind production at the time, and so needs to be evaluated specifically for each context. Generally, the greater the load in the OBZ created by the electrolyser compared to the transmission capacity available, the greater the probability that the price shifts to another higher priced market area. If the OWP capacity and the electrolyser capacity exceed the transmission capacity to the onshore market zones, the clearing price at the hub will be determined by the electrolyser, as the offshore wind cannot be evacuated to the onshore market areas. Similarly, in case of negative power prices at the OBZ (due to negative power prices in one or more of the connected market areas), additional demand by the offshore electrolyser may lead to a situation where the electrolyser will set the price in the OBZ. Consequently, the OWP will then no longer face negative prices that can positively affects its operation.

The operation of an electrolyser offshore can positively affect the trade capacities between the onshore market areas. This is the case if the OWP and the electrolyser operate simultaneously. Export and import capacities will be impacted by the balance of power production and power consumption at the hub. The general effect is similar in HZ and OBZ arrangements.

Locating an electrolyser at an offshore hub can increase the clearing price for the OWP if the hub operates under an OBZ. At the same time, the electrolyser systematically benefits from lower power prices in an OBZ compared to the power price it would face if located onshore or if the hub operated under a HZ arrangement. Furthermore, localising an electrolyser offshore can increase trade capacities between onshore market areas in case the OWP and the electrolyser operate simultaneously. This effect is similar in HZ and OBZ arrangements.

3.2 Principles for a coordinated approach for a CBA and CBCA of joint (hybrid) OWP

3.2.1 Introduction to societal CBA and CBCA approaches

To assess the feasibility of building a hybrid offshore project, the costs and benefits of the project need to be analysed through a CBA. When benefits outweigh costs over a certain period, the project has a positive net present value (NPV), adds value (to society), and is worth pursuing from a societal perspective. A CBA guideline presents an objective method, agreed upon by relevant stakeholders, to determine overall costs and benefits of a project. A societal CBA can be conducted for any project to assess its value to broader society (e.g. electricity, gas, storage). For grid infrastructure projects, one of the next phases after a positive CBA for large-scale cross border infrastructure is to identify which stakeholders receive benefits or costs as a result of the project. This will inform the cost allocation procedure and cost distribution between stakeholders. For cross-border projects, this involves a CBCA. This section identifies key guiding principles for the CBA and CBCA for hybrid OWPs in sections 3.2.2 and 3.2.3, respectively.

Scope and perspective of the CBA and CBCA of offshore hybrid projects

Hybrid OWPs combine multiple components and stakeholder perspectives. Components range from transmission system assets for the connection of offshore wind and cross-border interconnectors to generation and storage assets. These components are generally either part of the regulated asset base of national TSOs or part of the assets of a commercial project exploited by developers. Two key stakeholders for hybrid offshore projects are TSOs[249] and commercial developers; each have different investment incentives. Due to these inherently different incentives, current CBA approaches can take a societal, systemic view assessing the value of assets for (European) society (societal CBA) as is, for example, the case for cross-border transmission projects and the ENTSO-E CBA Guideline. Projects with the highest NPV should be prioritised and, if needed, supported. A CBCA will define the distributional effects of the societal costs and benefits between Member States and their reallocation. In contrast, a project view assesses the economic/financial value of the project to the developer (i.e. feasibility of the business case). A developer or investor will prioritise the project with the highest internal rate of return (IRR) to increase its profits. These two viewpoints impose different requirements to the CBA; for instance, an investment grant will add to the IRR of the project but does not influence

[249] When referring to TSO we assume this stakeholder includes the transmission asset ownership function together with system operation.

the NPV of the project from a societal perspective.[250] Figure 3-4 illustrates the difference in scope between a societal CBA, the CBCA and a project CBA.

Hybrid OWPs are generally part of large-scale cross-border infrastructure. These strategic projects can help the EU achieve its objectives to integrate large-scale offshore wind, increase the share of RES in the energy mix, and increase market integration between Member States to ensure an affordable and reliable energy system. Offshore hybrid projects require alignment and coordination between multiple Member States in terms of envisaged generation capacities, support scheme design, and grid connection regimes (section 3.1.1). Currently, infrastructure planning is done from a grid point of view to increase cross-border capacity. Hybrid projects could allow the combination of grid planning with planning of cross-border infrastructure based on high potential offshore RES zones. The first logical step to develop an offshore hybrid project is having the involved Member States and TSOs agree on the degree of cooperation and start defining project concepts that could go through the CBA process.

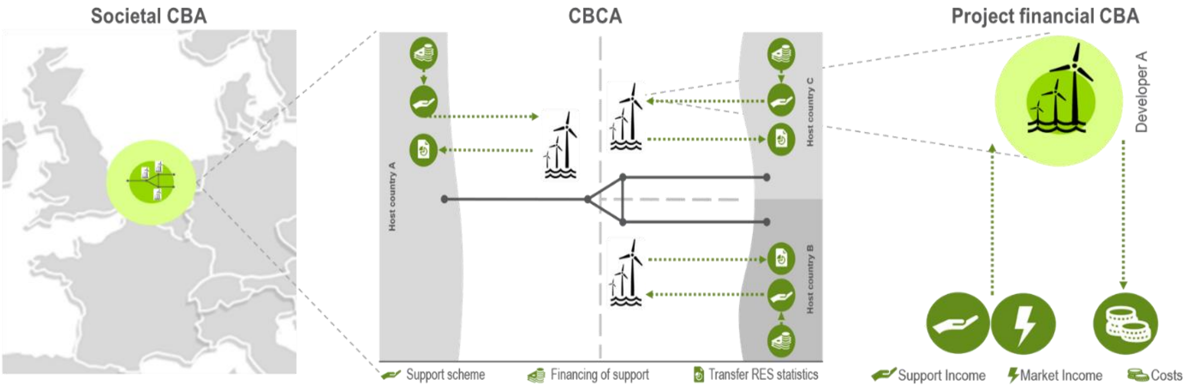


Figure 3-4. Scope and difference between a societal CBA on a system level, a CBCA reflecting distributional effects and a project specific CBA. *(Source: Guidehouse)*

This section identifies guiding principles for a societal CBA and CBCA for offshore hybrid projects to ensure to capture the most relevant cost and benefit aspects of hybrid OWPs and keep the CBA manageable.

3.2.2 Societal cost-benefit analysis

3.2.2.1 Introduction

As a first step in the CBA assessment of hybrid OWPs, we adopt a societal perspective to identify the most promising strategic projects with the highest socioeconomic welfare impact to European society. However, within this societal CBA, various components will result in costs and/or benefits for various stakeholders, including EU Member States, national TSOs, commercial project developers, and European bodies. Although some components could be a benefit to one stakeholder (e.g. subsidy for developer, grid fee for TSO), that same component could be a cost for another (e.g. subsidy for governments, grid fee for consumers). In a societal CBA, however, these components tend to net each other out.

[250] Progress on Meshed HVDC Offshore Transmission Networks (PROMOTioN), 2016-2020. https://www.promotion-offshore.net/; PROMOTioN, 2018. Deliverable 7.11 Cost-benefit analysis methodology for offshore grids. https://www.promotion-offshore.net/fileadmin/PDFs/Deliverable_7.11_-_CBA_methodology_for_offshore_grids_-_final_-_DNVGL20180817.pdf; Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

Several CBA approaches for (cross-border) electricity infrastructure, storage, and generation projects currently exist or are being investigated. An offshore hybrid project combines generation, transmission, and potentially other components (e.g. storage, sector coupling). To capture the impact of hybrid OWPs on society, generation, and interconnection, components should be considered as a single project. By assessing all components of a hybrid OWP together, the total societal costs and benefits can be captured completely, even though possibly not fully quantified and/or monetised. This requires viewpoints of different stakeholders and different CBA evaluation methods to be aligned and coordinated. The societal CBA should be defined to present an objective method, agreed upon by the relevant stakeholders, to determine overall costs and benefits of the project.

Most hybrid OWPs have a strategic value to the European energy system in terms of facilitating large-scale integration of renewables. They should support the main objectives as stipulated by the Regulation (EU) No347/2013 (TEN-E regulation):[251]

- Affordability linked to market integration by, for example, reducing bottlenecks on the transmission level they could increase competition within the European power market contributing to levelling power prices between Member States.

- Security of supply by increasing redundancy and flexibility in the European power system.

- Sustainability by facilitating the integration of renewable energy generation into the grid.

The economic, environmental, and social impacts of offshore hybrid projects and their contribution to the long-term EU policy goals will form the basis of their evaluation and the formulated CBA guiding principles. This section formulates guiding principles to inform a CBA framework to assess hybrid OWPs and their impact on European society as guidance for the CBA process. These principles are formulated to ensure objective, transparent, and complete comparison of offshore hybrid projects to a reference case (counterfactual). The CBA guiding principles inform the next step of formulating guiding principles for the CBCA for hybrid OWPs in section 3.2.3. The approach to formulate these CBA guiding principles includes the key elements that follow:

- **General framework societal CBA:** The general structure of a societal CBA is identified with the different topics that require guidelines and recommendations (see section 3.2.2.2).

- **Existing approaches to CBA:** An overview of relevant existing societal CBA approaches is provided. As hybrid OWPs generally have a strategic value to the European energy system, their value to society could follow the method used to evaluate transmission projects under the PCI process. The starting point of our analysis is the ENTSO-E Guideline for CBA for electricity infrastructure projects (V3.0).[252] This is complemented with insights from the TEN-E provisions for assessment of storage and cross-border generation projects to capture benefits and costs from the generation component of offshore hybrid projects (see section 3.2.2.3).

- **The most relevant topics and indicators for hybrid offshore projects:** An overview is provided for each of the topics in the CBA structure and includes the complexities and considerations for hybrid OWPs with learnings from the existing approaches (see sections 3.2.2.4 and 3.2.2.5).

- **CBA guiding principles:** Guiding principles for a societal CBA for hybrid OWPS are formulated based on the discussion and considerations from Step 3 (see section 3.2.2.6).

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[251] EC, 2019. Study on an assessment methodology for the benefits of electricity storage projects for the PCI process. Final report by Navigant. https://op.europa.eu/en/publication-detail/-/publication/4d333f57-d086-11e9-b4bf-01aa75ed71a1/language-en. *Note that the TEN-E regulation is about to be revised.*

[252] ENTSO-E, 2020. 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects. https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/tyndp-documents/Cost%20Benefit%20Analysis/200128_3rd_CBA_Guideline_Draft.pdf (Draft *3rd ENTSO-E Guideline for CBA*)

3.2.2.2 General framework for societal CBA

This section presents the first step in the approach to define guiding principles for a CBA for hybrid OWPs. Societal CBA methodologies have a general framework[253] with guidelines formulated along multiple topics as illustrated in Figure 3-5 and described below. The guiding principles for a CBA for hybrid OWPs are formulated along these topics.

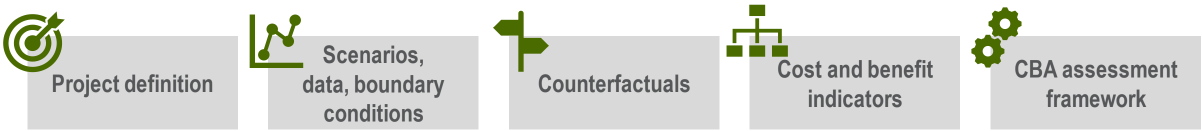

Figure 3-5. Topics of general framework societal CBA. *(Source: Guidehouse)*

Project definition

First the project needs be defined and can be brought forward by a project promoter. This includes technical project specifications such as the size, assets, and location of the project and any specific technical features and services to be provided (e.g. electricity, green hydrogen).[254] In addition, the scope of the project needs to be defined in terms of geographical impact (what countries to include in the assessment in a European setting) and sectors (which sectors to include in the assessment—only electricity or also gas. A set of project alternatives that fulfil a similar function with different sizes or technologies could be defined to be compared and assessed with the CBA to the counterfactual (see below). This allows us to identify the most impactful project from a set of alternatives.

Data, scenarios, and boundary conditions

A clear set of future energy system scenarios allows to assess projects on a common basis. A scenario defines the mid- and long-term development of the European energy system including developments in generation portfolio, technology cost assumptions, hydrogen generation, fuel and CO_2 prices, climate years for renewables, reference grid configurations, time horizon, time granularity, geographical scope, and energy demand. A scenario serves as input to any modelling tools required to perform the CBA (e.g. power market and network models) to estimate the future potential benefits of the project. Due to uncertainty with future outlooks, the project should be assessed under multiple scenarios that represent a robust range of possible futures. This ensures the project performs well under a range of different conditions, increasing the robustness of the outcomes of the CBA. Of course, a trade-off needs to be made between complexity and robustness of the analysis. In addition to a consistent set of scenarios for project evaluation, additional input data might be required such as costs of assets and assumptions on future cost reductions. Sensitivity on these parameters further adds to the robustness of the CBA analysis.

Any boundary conditions that will impact the operation of project in the energy system, potentially impacting the cost and benefit indicators, must be specified. One key boundary condition is the governing market design, including the bidding zone configuration, the project scope with regard to onshore grid reinforcements, and the envisioned cooperation setup, if applicable.

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[253] Progress on Meshed HVDC Offshore TransmissIOn Networks (PROMOTioN), 2016-2020. https://www.promotion-offshore.net/; PROMOTioN, 2018. Deliverable 7.11 Cost-benefit analysis methodology for offshore grids. https://www.promotion-offshore.net/fileadmin/PDFs/Deliverable_7.11_-_CBA_methodology_for_offshore_grids_-_final_-_DNVGL20180817.pdf; C. Wouters, W. van der Veen, P. Henneaux, M.J. van Blijswijk, 2019. A methodology for societal cost-benefit analysis for meshed offshore grids. CIGRE symposium Aalborg Denmark 4th-7th June 2019. https://www.promotion-offshore.net/fileadmin/PDFs/82_Wouters_CIGRE_Aalborg.pdf

[254] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

Counterfactual projects

Each project needs to be evaluated compared to a counterfactual. A counterfactual presents the base/reference case, including reference grid and reference energy system, for the comparison of different project alternatives. All project alternatives are evaluated in comparison to the counterfactual. A counterfactual can take on many forms: either a reference energy system could be evaluated with and without the project as adopted under the ENTSO-E Guideline (see section 3.2.2.3). Alternatively, a counterfactual could be a similar project with a different configuration. The counterfactual could then be standardised to enable comparison of multiple project alternatives to the counterfactual in a transparent and coherent manner. However, a common counterfactual for multiple project alternatives might not be identifiable or achievable. Case-specific counterfactuals might be required with a different and tailored project setup in terms of project size or technologies.[255] The latter is defined on a case-by-case basis by a project promoter but does not facilitate ready comparison between different project alternatives.

Cost and benefit indicators

Project alternatives are evaluated across a set of indicators representing cost and benefit impacts to society. An objective and comprehensive set of indicators should be defined to capture the economic, social and environmental viability of each project. Indicators can be expressed in monetary terms or expressed quantitatively or qualitatively. Generally, only a full set of monetised indicators allows for a perfect comparison of projects, as the costs and benefits are expressed on a common basis. In practice, however, monetisation or even quantification cannot always be achieved objectively or requires expensive and complex modelling efforts. These efforts may result in some indicators being expressed in quantitative or qualitative terms. The extent to which indicators can be objectively and readily monetised determines the overall assessment of the project.

A set of indicators should avoid double counting of costs and benefits (see section 3.2.2.5). Cost indicators generally cover the project's CAPEX and OPEX and are inherently monetised. Part of CAPEX and OPEX are support costs, which play a crucial role in the cooperation on RES generation assets. Benefits include a broader range of indicators reflecting direct and indirect impacts of the project on society that are usually not readily quantified or monetised. For each defined indicator, an approach should be defined on how to quantify or monetise it including required data or modelling tools (e.g. power market and network models), and an indication of which stakeholders are impacted by or responsible for this indicator.

Assessment framework

The assessment framework presents guidelines for the overall CBA. This could include an economic (NPV) analysis with guidelines on common assumptions for economic lifetime of components and interest rates. If not all indicators can be monetised, a multi-criteria assessment[256] would allow the comparison of each indicator's scoring against the counterfactual and to each other.

3.2.2.3 Existing CBA approaches

This section analyses existing CBA approaches for their applicability to hybrid OWPs along the general CBA framework.

(Cross-border) electricity infrastructure

[255] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

[256] ENTSO-E, 2020. 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects. https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/tyndp-documents/Cost%20Benefit%20Analysis/200128_3rd_CBA_Guideline_Draft.pdf (Draft *3rd ENTSO-E Guideline for CBA)*

Electricity infrastructure is often part of the regulated asset base of national TSOs. For grid development projects, an established CBA methodology exists at a European level. ENTSO-E is responsible for the development of a CBA guideline for grid development projects under the Regulation (EU) No 347/2013.[257] The second ENTSO-E Guideline for CBA of grid development projects (transmission and centralised storage projects) was approved by the European Commission in 2018.[258] Currently, the third ENTSO-E CBA Guideline is in the final stages of publication.[259] In May 2020, ACER published its opinion on the draft of the third ENTSO-E Guideline.[260] The third CBA Guideline builds further on the second Guideline with additional indicators and monetisation guidelines for indicators.[261] The ENTSO-E CBA Guideline assesses the costs and benefits of transmission TYNDP projects to European society as the basis for the European PCI process. The CBA guideline provides a common basis for the assessment of projects brought forward by project promotors based on their societal value. Cost and benefits indicators are expressed around the themes of market integration, sustainability and security of supply focusing on a system-CBA rather than a project-CBA. The Guideline formulates a common set of indicators, as well as guidelines on indicator evaluation, scenarios, modelling tools, assumptions and assessment.

Project evaluation is based on both monetised and non-monetised indicators resulting in a multi-criteria analysis assessment. The CBA guideline presents the basis for the evaluation of both internal and cross-border grid development projects, including the societal evaluation of system-benefits of centralised storage devices on transmission systems. Generation projects are not part of the ENTSO-E CBA guideline as they are not part of the grid development responsibilities.

The second ENTSO-E CBA guideline has been used as a basis for the developed CBA methodology for meshed offshore grids under the Horizon2020 PROMOTioN project.[262] The latter CBA methodology was developed to enable the evaluation of an offshore grid meshed system which develops over a few decades in contrast to the ENTSO-E CBA Guideline which focusses on single projects that are more bound in space and time.

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[257] ENTSO-E, 2019. Cost Benefit Analysis. https://tyndp.entsoe.eu/cba/

[258] ENTSO-E, 2018. 2nd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects. https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/tyndp-documents/Cost%20Benefit%20Analysis/2018-10-11-tyndp-cba-20.pdf

[259] ENTSO-E, 2020. 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects. https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/tyndp-documents/Cost%20Benefit%20Analysis/200128_3rd_CBA_Guideline_Draft.pdf (Draft *3rd ENTSO-E Guideline for CBA)*

[260] ACER, 2020. Opinion No 03/2020 of the European Union Agency for the Cooperation of Energy Regulators of 6 May 2020 on the ENTSO-E draft 3rd Guideline for cost benefit analysis of grid development projects.

[261] Draft *3rd ENTSO-E Guideline for CBA*

[262] Progress on Meshed HVDC Offshore TransmissIOn Networks (PROMOTioN), 2016-2020. https://www.promotion-offshore.net/; PROMOTioN, 2018. Deliverable 7.11 Cost-benefit analysis methodology for offshore grids. https://www.promotion-offshore.net/fileadmin/PDFs/Deliverable_7.11_-_CBA_methodology_for_offshore_grids_-_final_-_DNVGL20180817.pdf; C. Wouters, W. van der Veen, P. Henneaux, M.J. van Blijswijk, 2019. A methodology for societal cost-benefit analysis for meshed offshore grids. CIGRE symposium Aalborg Denmark 4th-7th June 2019. https://www.promotion-offshore.net/fileadmin/PDFs/82_Wouters_CIGRE_Aalborg.pdf

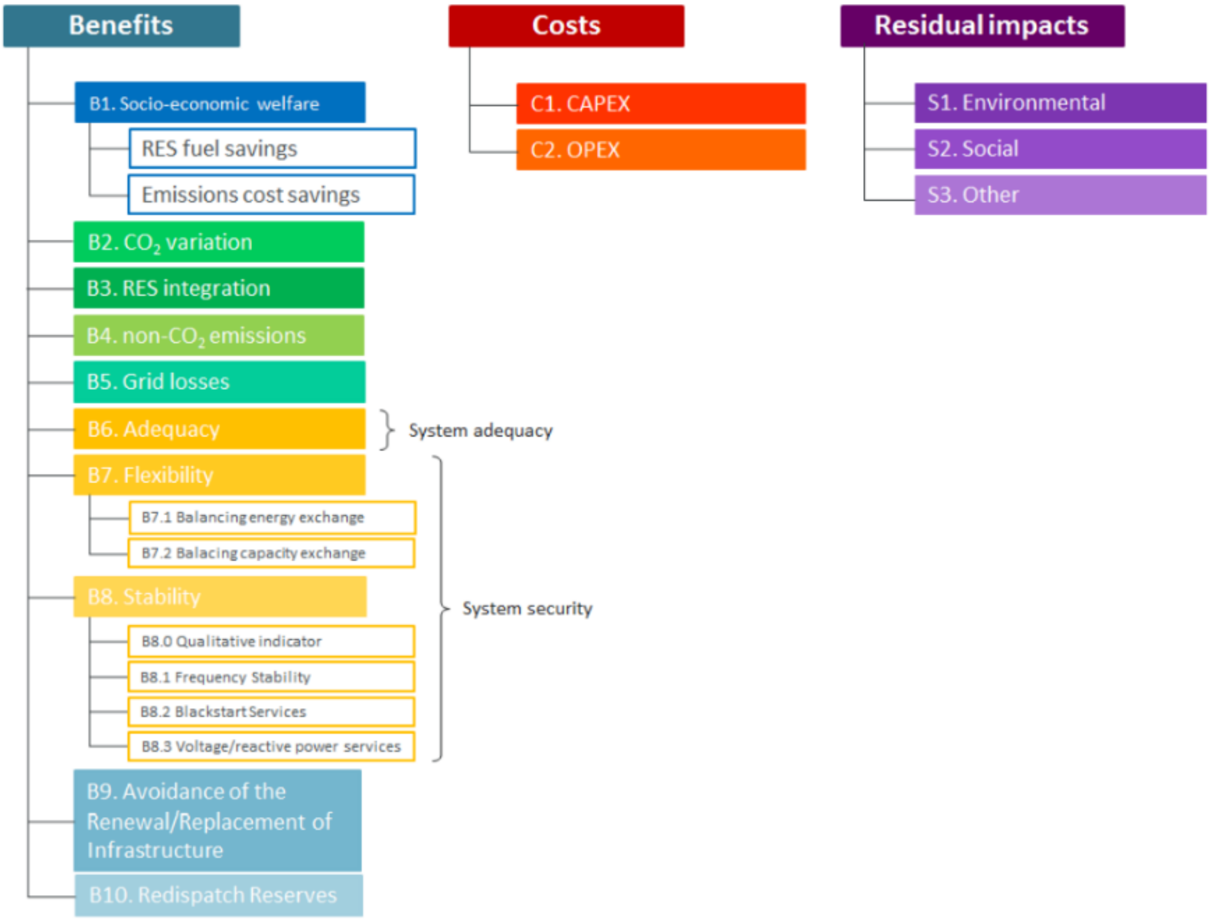

Figure 3-6. Illustration of the different categories of cost and benefit indicators used for project assessment under the draft third ENTSO-E CBA Guideline. *(Source: ENTSO-E, 2020)*[263]

(Cross-border) renewable energy or storage projects

CBA analyses of generation projects generally focus on assessing the project's business case from the financial perspective of the project promotor rather than on a macroeconomic level assessing the societal value the generation project adds. Several ongoing developments investigate the evaluation of generation projects within a societal context. This comes into play for cross-border projects where cooperation mechanisms and support schemes might require alignment.

RED II (focus on RES statistics and support costs)

Cooperation on renewable (RES) generation projects is legally embedded into the RED I and II.[264] The main rationale is to use RES potential across Europe more cost-effectively compared to purely national approaches to RES support. One Member State may access more cost-effective RES potential of another Member State than its own potential. One (contributing) Member State makes support payments to a generation asset in another (hosting) Member State and in turn receives RES statistics that contribute towards their RES share. As a result, it will typically save support costs. The process starts with Member States agreeing to cooperate and agreeing on volumes and the support scheme setup. In parallel, the RES project developer (unless done centrally) predevelops projects as

[263] Draft *3rd ENTSO-E Guideline for CBA*

[264] See for a detailed discussion Klessmann et al 2014: Cooperation between EU Member States under the RES Directive. https://ec.europa.eu/energy/sites/ener/files/documents/2014_design_features_of_support_schemes_task1.pdf and von Blücher et al. 2018: Design options for cross-border auctions, available at http://aures2project.eu/wp-content/uploads/2019/06/AURES_II_D6_1_final.pdf.

part of its project pipeline. Subsequently, Member States or a subordinate agency implements the RES auction and the selected RES projects are being built by the developer.

The RED I and II focus on generation assets and do not define a general CBA approach, not to speak of a detailed CBA methodology. When assessing costs and benefits between Member States, there is no claim for a comprehensive analysis. The aim is on selecting the most important cost and benefit factors to support the political will to cooperate. Limiting the analysed cost and benefit elements reduces the complexity and the transaction costs of the cooperation. Typical elements of assessing costs and benefits in the context of the cooperation mechanisms are RES statistics as the main benefit and support costs as the main cost. In addition, RES integration costs (i.e. cost for grid reinforcement and additional redispatch) are sometimes considered as well.

Joint projects as defined under the RED I and II have not been implemented so far, except for the German-Danish PV tender. Considerations on how costs and benefits ought to be addressed for joint projects are based on case studies and research projects on the topic.

CBA principles for cross-border RES projects under the Connecting Europe Facility (CEF)[265]

In this report, conducted by Guidehouse (formerly Navigant) and EY principles for a system-level CBA for cross-border RES projects were identified to evaluate cross-border RES projects in line with the political agreement on the CEF regulation:[266]

> “the project specific cost-benefit analysis pursuant to point 3 of Part IV of the Annex shall be compulsory for all supported projects, shall be performed in a transparent, comprehensive and complete manner and shall provide evidence concerning the existence of significant cost savings and/or benefits in terms of system integration, environmental sustainability, security of supply or innovation.”

The report identifies basic steps in a system-level CBA (in line with section 3.2.2.2) and identifies guiding principles to capture the costs and benefits of cross-border renewable projects on a societal level, always in comparison to a non-cooperation case. A key specification for cross-border RES projects was identified as the selection of cooperation mechanism and assessing the added value of cooperation in comparison to a project without cross-border cooperation. The report considers the seven elements specified under the CEF regulation for a CBA of a cooperation project to assess the added value of cooperation:

- Cost of energy generation
- System integration costs
- Cost of support
- Greenhouse gas emissions
- Security of supply
- Air and other local pollution
- Innovation

With generation projects, the cost of support payments is a topic of discussion between CBA approaches as emphasised in this report. Most societal CBA approaches consider support payments

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[265] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

[266] Council of the European Union, 2019. Interinstitutional File: 2018/0228(COD). https://data.consilium.europa.eu/doc/document/ST-10418-2020-INIT/en/pdf

not part of the NPV analysis of the CBA with the rationale that support payments reflect transfer payments related to the agreed distribution of costs rather than a societal benefit or cost (left pocket, right pocket situation). The CEF regulation, in contrast, requires cost of support as an indicator in the CBA analysis. The report tries to merge both views by quantifying the cost of support as part of the input of the project selection project but not as input for the CBA NPV assessment.

Benefits of electricity storage projects for the PCI process[267]

This report looked at improving the second ENTSO-E CBA guideline to better capture the benefits of candidate electricity storage PCI projects. Additional benefits and approaches to monetise benefits where identified. The value of candidate storage projects was evaluated from a societal perspective rather than a financial project perspective. The identified benefits were:

- Market-based socioeconomic welfare including RES integration and reduction of CO_2 cost
- Generation capacity deferral
- Reduced costs for ancillary services (reserve capacity, frequency regulation)
- Adequacy to meet demand
- Transmission capacity deferral
- Reduction of grid losses
- Facilitating additional RES integration (improved RES business case)
- Additional impact of avoided CO_2 emissions
- Reduction of non-CO_2 emissions

Summary and comparison of existing approaches

Table 3-10 summarises the discussed societal CBA approaches based on the general CBA framework. This summary feeds into the discussion on the considerations and gaps for the analysis of offshore hybrid projects.

[267] EC, 2019. Study on an assessment methodology for the benefits of electricity storage projects for the PCI process. Final report by Navigant. https://op.europa.eu/en/publication-detail/-/publication/4d333f57-d086-11e9-b4bf-01aa75ed71a1/language-en

Table 3-10. Comparison of discussed existing CBA approaches along general CBA framework.[268]

		ENTSO-E CBA V3.0	CBA c-b RES under CEF	Benefits storage projects PCI process
Project definition	**Type of asset**	Grid development projects	Cross-border RES projects	Storage projects
	Geographical scope	At minimum all EU27 Member States and applicable third countries where assets will be built or that will be significantly impacted by the project	At least countries involved and third countries impacted	In line with ENTSO-E CBA guideline
	Sector scope	Electricity	Electricity	
Data, scenarios and, boundary conditions	**Scenarios and data**	TYNDP scenarios	Consistent, common set of scenarios	In line with ENTSO-E CBA guideline
	Boundary conditions (market design)	Current home market offshore bidding zone design	Cooperation mechanism, bidding zone design, and RES support design	
	Uncertainty	Multiple scenarios Sensitivities on parameters	Recommended projects assessed against multiple scenarios, sensitivities on parameters	
Counterfactuals	**Assessment approach**	Reference network with TOOT or PINT[269]	One core eligibility criterion of the CEF regulation the c-b RES project shall "*provide cost savings in the deployment of renewables and/or benefits for system integration, security of supply or innovation in comparison to a similar project or renewable energy project implemented by one of the participating member states alone*" Standardised or case-specific defined by project promotor	In line with ENTSO-E CBA guideline

[268] Third countries are countries not part of EU-27.

[269] The ENTSO-E Guideline presents two methods to assess the impact of the project compared to a reference network; TOOT, *Take out one at a time*: the project is included in the reference network and then taken out to evaluate its impact on the system. PINT, *Put in one at a time*: the project is not part of the reference network and then included to the reference to evaluate its impact on the system.

		ENTSO-E CBA V3.0	CBA c-b RES under CEF	Benefits storage projects PCI process
Cost and benefit indicators	**Degree of monetisation/ quantification**	Combined cost-benefit and multi-criteria analysis	Monetisation of indicators as much as possible	All indicators monetised
	Cost indicators	CAPEX OPEX	Cost of energy generation System integration costs Cost of support (not of societal value)	In line with ENTSO-E CBA guideline
	Benefit indicators	• Socioeconomic welfare • CO_2 variation • RES integration • Non-CO_2 emissions • Grid losses • Adequacy • Flexibility • Stability • Avoidance of the renewable/replacement of infrastructure • Redispatch reserves	• Greenhouse gas emissions • Security of supply • Air and other local pollution	• Market-based SEW including RES integration and reduction of CO_2 cost • Generation capacity deferral • Reduced costs for ancillary services (reserve capacity, frequency regulation)' • Adequacy to meet demand • Transmission capacity deferral • Reduction of grid losses • Facilitating additional RES integration (improved RES business case) • Additional impact of avoided CO_2 emissions • Reduction of non-CO_2 emissions
	Other indicators	Environmental, social and other residual impacts	Innovation	In line with ENTSO-E CBA guideline
Assessment	**NPV**	Yes for monetised indicators	Yes for monetised indicators	Yes
	Discount rate and lifetime	4% real discount rate 25 years economic lifetime	4% real discount rate Technology specific project lifetime	4% real discount rate Technology-specific economic lifetime: 50 years PHEV, 35 years CAES
	Residual value	Zero at end of life	Zero at end of life	Zero at end of life
	Multi-criteria analysis	Yes for non-monetised indicators	Technical feasibility and environmental sustainability Economic analysis	N/A

		ENTSO-E CBA V3.0	CBA c-b RES under CEF	Benefits storage projects PCI process
Others	**Tools and mechanisms**	Market and network models	Market and network models and choice of cooperation mechanism	Use of benchmarking for monetisation of indicators

3.2.2.4 The most relevant topics for hybrid offshore project CBAs

Introduction

Currently, generation and grid development projects are established following different principles: project profitability versus part of regulated asset bases or strategic projects. This is reflected by different CBA methodologies. Storage projects are already part of the ENTSO-E CBA process through their societal benefits. This could pave the way for the societal evaluation of generation projects as part of hybrid OWPs.

For generation projects, there are several ongoing initiatives to develop CBA guiding principles to capture societal benefits, in particular for cross-border renewable projects. Insights from these current methodologies are combined to develop guiding principles for a societal CBA for hybrid OWPs. The interconnection and generation components of an offshore hybrid project could be considered as a single project in this context, so that the costs and benefits can be regarded holistically. When moving towards the development phase, this leaves room for Member States to break up the project in regulated and tendered parts and to negotiate or prioritise projects politically as they wish and as is compliant with state aid rules and unbundling requirements. This assumes a significant coordination effort and political commitment; sequencing of planning and development of hybrid OWPs needs to be merged with achieving the highest socioeconomic welfare for Europe. With this approach, hybrid OWPs could take part in the PCI process and could receive additional funding as strategic projects. For hybrid OWPs, Member State-driven cooperation is likely to play a role and Member States can push their hybrid OWPs forward complementary to the PCI process if they think they are worth pursuing. However, within this exercise there are several components that represent costs or benefits for various stakeholders, relevant to a proper allocation and possible redistribution of these costs and benefits (see section 3.2.3).

Following the general framework for a CBA (section 3.2.2.2) and the various relevant existing CBA approaches (section 3.2.2.3), the following key considerations can be made for CBA guiding principles for hybrid OWPs:

Cooperation mechanism and support payments

One key question regards the cost for support payments to developers for the offshore generation part of hybrid projects. Currently, offshore wind in Europe is mostly developed through tenders, with some recent zero-bid winning developments in Germany and the Netherlands (see Task 1). With hybrid OWPs likely connecting offshore wind farms further to offshore in potentially more complex conditions (including the market arrangement), support payments could still be required. Support costs are an important cost indicator under the CEF regulation for the CBA of cross-border renewable projects.[270] However, when looking from a societal perspective, support payments would be mere a transfer of payments from a government to a developer (cost redistribution) and would only come into play during the CBCA. These key considerations create boundary conditions for the societal CBA and link to the scope of the CBCA (see section 3.2.3).

Grid delivery model

The governing grid delivery model(s) within the development of a hybrid OWP will determine the roles and responsibilities for developing offshore wind transmission assets for the respective TSOs and developers (see Task 1 and section 2.2). As highlighted in Task 1, various grid delivery models exist, each with their advantages and disadvantages. Developers and TSOs have access to different financing conditions, where the TSOs—in particular, government-backed TSOs—typically have access to more favourable financing conditions (lower debt and equity return rates) compared to a commercial developer. From a societal viewpoint, this distribution does not have impact as overall costs and benefits of the whole project should be approached from a societal (e.g. TSO/government)

[270] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

perspective. However, it will impact the cost and benefit distribution for various stakeholders (developers, commercial transmission asset operators, TSOs) and the required distributional effects for the CBCA (see section 3.2.3).

Market design

For hybrid OWPs, the governing offshore market design is of major importance; it will impact the quantification and monetisation of some indicators and the selection and definition of counterfactuals, as well as the CBCA in the distributional effects of costs and benefits.

Offshore hybrid project configuration

The adopted societal CBA approach depends on the configuration of the hybrid OWP and the hardware components that it includes (see section 3.1.3). No new guidelines need to be formulated for a system-based CBA for OWPs only consisting of a generation (including grid connection assets such as radial connections and offshore switching stations or hubs) component, such as configurations 1 and 2 (see section 3.1.3). These configurations regard a form of cross-border RES projects and could either be assessed by Member States based on their preferences (even without a full CBA) or follow the guidelines for societal CBA as presented under the cross-border CBA study following the CEF.[271] The following sections present analysis relevant to the capture the full societal costs and benefits of hybrid OWPS combining generation and interconnection components reflected through configurations 3 to 5 (see section 3.1.3).

General considerations and project definition

Existing CBA approaches mostly focus on the evaluation of a project consisting of one type of component (transmission infrastructure, generation or storage) and one sector; either electricity or gas infrastructure. Hybrid OWPs combine different components and potentially different sectors through power-to-gas, increasing the complexity of the CBA. A CBA of a hybrid OWP could be developed along a comprehensive framework including cost benefits of different components and sectors, or through coordination of existing CBA approaches of the components and sectors included in the offshore hybrid project. The latter could be a potential modular CBA approach combining insights of the CBA of the different components depending on project setup (see Task 2.1). Scoping of the project and project evaluation in terms of space and time are also important when defining a project.

Geographical and temporal scope of the project

The project's geographical start and end points depend on what assets and investments are considered part of the project. A narrow project definition could include all assets required to develop the project up to the connection point to the respective onshore grid(s). In practice, and for hybrid OWPs connecting large capacities of offshore wind to shore, significant onshore grid reinforcements or investments might be required to transport the offshore wind energy to load centres. This could imply a wider project scope.

A CBA looks at the relative benefits and cost of a project compared to a counterfactual (Delta). The CBA methodology developed under the PROMOTioN project, for example, suggests ensuring connections of offshore infrastructure to onshore substations with sufficient hosting capacity and to include any grid investment cost up until that point as it is not achievable from a practical viewpoint to do a full grid development plan of the European grid. [272]

[271] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

[272] Progress on Meshed HVDC Offshore TransmissIOn Networks (PROMOTioN), 2016-2020. https://www.promotion-offshore.net/; PROMOTioN, 2018. Deliverable 7.11 Cost-benefit analysis methodology for offshore grids. https://www.promotion-offshore.net/fileadmin/PDFs/Deliverable_7.11_-_CBA_methodology_for_offshore_grids_-_final_-_DNVGL20180817.pdf

A hybrid OWP can be more compact in investment timeline than development of its components separately. This could imply (in case of a highly centralised development approach) that once tenders are awarded for the offshore wind farms, and with appropriate planning of transmission assets, the full project could be developed in a few years and investments could be clustered as stipulated under the ENTSO-E CBA Guideline:[273]

> "In some cases, a group of investments may be necessary to develop transmission capacities (i.e., one investment cannot perform its intended function without the realisation of another investment). This process is referred to as the clustering of investments. In this case, the project assessment is done for the combined set of clustered investments."

Under the ENTSO-E CBA guideline, clustering of investments can only take place if the investments are in similar stages of maturity. By contrast, the full hybrid OWP could also be developed in multiple phases, for example, when an offshore hub concept is included. The latter could have high upfront investment costs or anticipatory investments, resulting from the hub where offshore wind farms would be connected in multiple stages. This could complicate the clustering rules set out under the ENTSO-E CBA guideline depending on the stage of development of the different components and assets of the project at the start of development.

Geographical and temporal scope of the project evaluation

The scope and description of the context of the project also should be defined geographically and temporally. For hybrid OWPs, the same considerations would hold as described under the ENTSO-E CBA guidelines:

- Geographical scope for project evaluation: EU27 countries and any third countries where assets would be built or that would be significantly impacted by the project.

- Temporal scope of project evaluation: Mid- to long-term horizon.

Data, scenarios, and boundary conditions

All analysed CBA approaches recommend evaluating a project under multiple energy system scenarios to ensure the robustness of the CBA results. Scenarios should provide a clear and common basis for project comparison. Within the ENTSO-E CBA guideline these are the TYNDP scenarios for the medium- and long-term.

To provide a common basis for project comparison, boundary conditions should be established. These boundary conditions could complicate the evaluation of offshore hybrid projects. One main boundary condition is the governing market design. More specifically, the OBZ configuration determines market revenues for the generation component and congestion rents of the interconnector components and the dynamics within the energy system. The governing market design could impact the indicator evaluation of the offshore hybrid project and the CBCA (see section 3.2.3). A key consideration is whether the bidding zone configuration (and by extension market design) would be the same under the offshore hybrid project as under the counterfactual. An offshore hybrid project might warrant a change in market design which might not be required for the development of the counterfactual project, impacting the common base of assessment.

Counterfactuals

A counterfactual presents the base/reference case for the comparison of project alternatives. A counterfactual can take on many forms. The counterfactual could take the form of a reference energy system and this system could be evaluated with and without the project like under the TOOT and

[273] Draft *3rd ENTSO-E Guideline for CBA*

PINT approaches defined under the ENTSO-E CBA guideline.[274] The counterfactual is the system with or without the project and the analysis evaluates the incremental benefits of the project to the European energy system. For some larger and more complex configurations of hybrid OWPs where multiple investments are spread out in time, this might not be suited as counterfactual.

Another type of counterfactual could therefore be defined as a similar project with a different configuration. Important considerations are the capacity of RES generation connected to the project, levels of interconnectivity between bidding zones, and the location (geographical and bidding zone) of assets in the project and how these relate to the counterfactual. A key question for a counterfactual defined as similar project—either standardised or tailored—might be what interconnector configuration should be assumed in the counterfactual scenario. This could be no level of interconnection, the same level of interconnection capacity but independent of a specific wind project and fully open to trade or a different capacity that provides the same level of interconnection to the market. The definition of a project counterfactual is open to interpretation but could be defined along two lines:[275]

- **Standardised counterfactual:** Enables ready comparison between multiple alternative projects in a transparent and coherent manner. The counterfactual could be defined as connecting the same capacity and technology of RES, perhaps in the same location with a different configuration of grid connection, combined with a separate interconnector. This counterfactual could reflect the characteristics of the offshore hybrid project (RES and interconnection capacities) but with currently established technologies and practices (radial offshore wind farm connections to home markets and interconnectors). However, it might not be readily possible or desirable to identify a standardise counterfactual. In addition, some considerations could be made in the setup of the counterfactual. For example, for case 3 (see section 3.1.3), the counterfactual could be defined as two separate wind farms installed in each respective Member State and an interconnector between the Member States. This counterfactual project definition would imply that the generation parts would fall out of the CBA analysis as they no longer involve a cross-border aspect and would be part of national development plans. Another counterfactual for case 3 could for example be case 4 where instead of one wind farm installed in each Member State, these are merged to one larger wind farm in one Member State. Case 4 could, however, also be a project alternative implementation to case 3 in the comparison with another counterfactual.

- **Case-specific counterfactual:** Might be required with a different and tailored project setup in terms of project size or technologies. The latter can be defined on a case-by-case basis by a project promoter but does not facilitate ready comparison between different project alternatives. The case-specific counterfactual could represent different boundary conditions that would not require changes for the offshore hybrid project, like alignment in grid delivery model, definition of cooperation mechanism or market design (bidding zone configuration).

3.2.2.5 Cost and benefit indicators

A set of indicators needs to be defined to capture the key costs and benefits of hybrid OWPs from a societal perspective. In line with general European infrastructure project evaluations, we adopted the societal perspective to assess whether a project is worth pursuing. Within this exercise there are several components that could be considered costs or benefits for various stakeholders. This will be further detailed in this section and in the guiding principles for the CBCA. Member States are free to develop cooperation projects regardless of whether an institution body outside these Member States

[274] The ENTSO-E Guideline presents two methods to assess the impact of the project compared to a reference network; TOOT, *Take out one at a time*: the project is included in the reference network and then taken out to evaluate its impact on the system. PINT, *Put in one at a time*: the project is not part of the reference network and then included to the reference to evaluate its impact on the system.

[275] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

deems other projects more preferential. Member States have the freedom to determine their energy system development plan and are free to determine their energy mix and to cooperate.

When defining a set of indicators, three main considerations need to be discussed: (1) the degree of monetisation of indicators, (2) avoiding double counting of cost and benefits of generation and grid components, and (3) the scope of direct effects translated to indicators.

(1) Monetisation and quantification of indicators

The degree of monetisation of indicators determines the assessment method (comprehensive NPV analysis vs. multi-criteria analysis). The general recommendation of existing CBA approaches is to monetise or at least quantify as many indicators as possible to enable transparent and ready project comparison. A trade-off should be made between (modelling) efforts required for monetisation and quantification of indicators, and impact on CBA robustness. The ENTSO-E CBA Guideline includes monetised, quantified and qualitative indicators in a multi-criteria analysis. This increases subjectivity of the evaluation process.

Monetisation can be achieved through various approaches, including through data provided by project promotors (e.g. CAPEX and OPEX), through modelling (e.g. socioeconomic welfare through power market modelling), through agreed parameters or through benchmarking.[276] Although monetisation enables a project comparison by combining all indicators in a single equation, it also often includes a subjective interpretation, a political discussion or complex quantification and modelling efforts. For example, adequacy can be quantified through determining the energy not served under the set of scenarios through a power market model. The value of lost load (VoLL) parameter could be used to monetise this quantified indicator. However, there is no single method to determine the VoLL of a system.[277] The VoLL depends on the regional, sectorial, and national differences in demand and supply, and the value of energy to consumers in a market. Subjectivity in monetisation could be addressed by placing the responsibility of monetisation of indicators on a single objective party, such as ENTSO-E, ACER, or the EC, to ensure consistency in the monetisation process. However, ENTSO-E, ACER, or the EC would have to make decisions on monetisation options that are subject to interpretation and could be contested by impacted stakeholders. Project promotors could put forward data on costs and missing benefits if they have access to better quality data or evaluation methods for their specific projects.

Benchmarking could be an appropriate parameter to monetise missing benefits that cannot readily be monetised through other approaches. However, a hybrid OWP might comprise novel assets and components, such as HVDC switch gear, limiting the data available for benchmarking.

(2) Double counting of costs and benefits

Indicators need to be developed carefully to ensure each indicator is unambiguously defined so as not to double count costs or benefits of a project. For example, cost of support payments to renewable energy developers are already part of the generation costs of the system, and the cost for the grid connection of a renewable energy generator should either part of generation or transmission infrastructure scope (depending on the grid delivery model).

(3) Direct and indirect effects translated to indicators

A project can have a range of direct and indirect effects on the energy system. We recommended a set of relevant indicators based on the analysed existing approaches and including any missing effects. The compact set of relevant indicators should be defined focussing on those indicators that capture the largest impact of the project on European socioeconomic welfare and power system through direct effects, for instance, CAPEX or RES integration. Various indirect indicators can also be

[276] EC, 2019. Study on an assessment methodology for the benefits of electricity storage projects for the PCI process. Final report by Navigant. https://op.europa.eu/en/publication-detail/-/publication/4d333f57-d086-11e9-b4bf-01aa75ed71a1/language-en

[277] Draft *3rd ENTSO-E Guideline for CBA*

defined but these are likely to be outside of the direct influence or behaviour of the project (such as job creation) as this depends on specific assets, subjective definitions of direct, indirect and derived employment effects, and the whole supply chain which is presumably partly outside the EU borders. Indirect effects are additionally not straightforward to monetise or even quantify (e.g. innovation and tourism effects). Their effect is often ambiguous and subjective, limiting their applicability in the assessment.

With the three above considerations in mind, we developed a recommended list of cost and benefit indicators applicable to offshore hybrid projects (see Table 3-11).[278] The following sections detail the indicators and their scope.

Cost indicators

From a societal perspective, the CBA should include cost indicators reflecting the key societal cost impacts of both infrastructure and generation components of the project. The starting point of our analysis was the set of cost indicators from the ENTSO-E Guideline complemented with renewable generation-specific costs. Figure 3-7 indicates the discussed categories of cost indicators for hybrid OWPs. For example, cost needs to include additional RES integration costs for the generation asset, which is not yet accounted for in the cost indicator in the ENTSO-E Guideline. This approach resulted in a long-list of possible cost indicators which was condensed to a compact, relevant set of indicators as Table 3-11 presents. We provide our rationale below on which indicators are or are not recommended for the evaluation of hybrid OWP.

Figure 3-7. Overview of main categories of cost indicators for hybrid OWPs.

CAPEX

This indicator should include all CAPEX related to the project during development. According to the definition under the ENTSO-E CBA Guideline, this indicator includes both project inception and sustaining CAPEX and encompasses:

> "elements such as the cost of obtaining permits, conducting feasibility studies, obtaining rights-of-way, ground, preparatory work, designing, dismantling, equipment purchases and installation" for grid development projects.[279]

This indicator also includes costs for temporary solutions to realise the project and any costs for consenting procedures. In addition, costs related to dismantling and any replacement and upgrades throughout the project lifetime are to be considered. CAPEX is expressed in € per year and is inherently monetised.

The definition of grid development CAPEX should be extended with the respective costs of the generation component and the offshore grid transmission assets (grid connection) of the generation component. In addition, the following CAPEX should be considered from a societal perspective:

- *Replacement costs* of the infrastructure and generation component assets, *lifetime extension costs* and *cost of modernisation* over the total economic lifetime of the project.

[278] Note that projects may also have a negative impact on some indicators, in which case negative benefits are reported.
[279] Draft *3rd ENTSO-E Guideline for CBA*

- *Costs for any environmental impact assessment and measures*: Defined as the outcome of the EIA procedure.[280]

- *Cost of site (pre-)development:* For the offshore RES sites and grid connections, including costs for surveys, planning, resource assessments.

- *Labour costs*: Installation, maintenance, and operation costs are included in the overall CAPEX and OPEX indicators.

- *Financing costs:* Including costs such as dividends and interest and loan payments.

Other capital costs put forward in the report on cross-border RES[281] include costs specific to the generation project from a business case perspective. These costs are not yet included or relevant in a societal CBA setting but will come into play throughout the CBCA and project CBA stages after the societal CBA proves positive.[282] Care should be taken in definition of the CAPEX indicator to avoid double counting of costs:

- A clear definition of grid delivery model can avoid double counting the cost of grid connection (responsibility for offshore renewable transmission assets, including substations).

- The CEF[283] includes cost of energy generation as an indicator for generation projects. However, this already includes all CAPEX and OPEX of the project and should not be included as a separate indicator.

OPEX

This indicator should include all O&M costs related to the project's ongoing O&M over the assessment period. According to the definition under the ENTSO-E CBA Guideline for grid development projects, this indicator includes:

> "the annual operating and maintenance expenses associated with the project or investment."[284]

OPEX is expressed per year and inherently monetised; it is typically expressed as a percentage of yearly CAPEX unless other data is available. The OPEX of both generation and transmission components should be included in the indicator.

Care should be in the definition of the OPEX indicator to avoid double counting of cost:

- Excluded from the OPEX are other operational costs, such as system losses. These are covered under a benefit separate indicator (grid losses).[285]

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[280] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).
[281] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).
[282] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).
[283] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).
[284] Draft *3rd ENTSO-E Guideline for CBA*
[285] Draft *3rd ENTSO-E Guideline for CBA*

Cost of onshore grid reinforcement

Depending on the configuration of the hybrid OWP, limited to extensive onshore grid reinforcements might be required to ensure offshore renewable or imported energy is transported to load centres and to alleviate potential bottlenecks in the onshore transmission systems of the relevant countries. The extent of onshore grid reinforcements is also impacted by the project scope; some reinforcements might be part of the project's scope (part of CAPEX) and others are outside of it. Double counting should be avoided. In addition, the counterfactual should adhere to the same project scope to ensure objective comparison.

Cost of onshore grid reinforcements is expressed in € per year and is inherently monetised. The cost of onshore grid reinforcements might be difficult to evaluated due to potentially complex market and network modelling efforts required. In addition, transparency on whether onshore grid reinforcements are required as an effect of the project or due to other system behaviour could be lacking. Dedicated benchmarking and cost estimates by impacted TSOs and DSOs of countries connected through the hybrid OWP could provide cost estimates. If data is available, costs for onshore grid reinforcement would include the same cost parameters as the CAPEX indicator. This is not recommended for the CBA due to the uncertainty, complexity, and ambiguity of this cost indicator. Relevant onshore grid reinforcement costs would already be part of the project scope and included in the CAPEX indicator.

Additional generation-related costs

Other generation-related costs indicators could be identified:

- **Cost of support payments:** This indicator is defined under the CEF as required for cross-border RES projects. Certain CBA approaches consider support payments not part of the NPV analysis of the CBA with the rationale that support payments reflect transfer payments related to the agreed distribution of costs rather than a societal benefit or cost. The CEF regulation requires cost of support as an indicator in the CBA analysis. As support costs are not a direct societal costs of generation projects but reflect a redistribution of costs between stakeholders in a hybrid project, this indicator is not included as part of the CBA but rather the CBCA (see section 3.2.3).[286]

- **System RES integration costs:** This indicator reflects the systemwide costs (and benefits) of the integration of the project, including cost of market integration, reduction of energy costs for substitution of the energy source, improved energy efficiency, effects on operational costs of the system, such as balancing costs.[287] These costs could be determined through power market and grid modelling. Care should be taken in the definition of this indicator to avoid double counting of costs and benefits. This indicator encompasses multiple separate cost and benefit indicators as described in the following sections. To ensure transparency of the project effects on the system and to avoid double counting, this indicator is not included but is split out in the different high impact cost and benefit indicators.

- **Balancing costs:** Generation has costs or revenues associated to balancing operation in the electricity market(s). Balancing costs are already internalised in project costs through balancing responsibility. They will be internalised in the bid of the project developer or operator and are not recommended to be part of the CBA. Balancing effects are, however, included on a system level to evaluate the effect of the project on system flexibility (see security of supply benefits).

[286] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

[287] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

- **Redispatch costs:** Additional redispatch costs for the generation unit should not be explicitly considered. The quantification of redispatch costs is possible ex post but only for specific control areas. Costs for the redispatch are socialised through grid tariffs. Systemic impacts on redispatch reserves of the project are included in a separate benefit indicator (see benefits).

- **Sale and purchase of energy – Cost of energy generation – Proof of financial viability:** From a societal perspective, the impact of the project on socioeconomic welfare captures the effects of generation dispatch, interconnection, or cost of purchasing energy for storage investments. The business case of the generation project will be part of the project CBA in a later stage after the hybrid OWP proves to be beneficial from a societal perspective. This business case analysis will impact the bidding behaviour of developers in the tender processes. The above are internal variables part of the modelling of the socioeconomic welfare indicator (benefit) and will not be considered as a separate indicator for the CBA.

- **Costs of financing:** These costs are included in the economic analysis since these have a significant influence on the viability of RES assets. Between-country differences in financing cost may be a major value driver for cross-border RES projects.

Benefit indicators

From a societal perspective, the CBA should include benefit indicators reflecting the key societal impacts of both infrastructure and generation components of the offshore hybrid project. We began our analysis with the set of benefit indicators from the ENTSO-E Guideline complemented with renewable generation-specific benefits. The evaluation approach on the benefit of RES integration takes on a different form for generation projects compared to grid development projects. A long list of benefit indicators was condensed to a compact set of indicators (Table 3-11). Figure 3-8 includes the categories of benefit indicators for hybrid OWPs. We focus on the benefits that have the largest expected impact on a European energy systemic level. The indicators that are and are not recommended to be part of the final set of indicators are briefly discussed below. Benefits are formulated around the themes of affordability, sustainability, and security of supply.

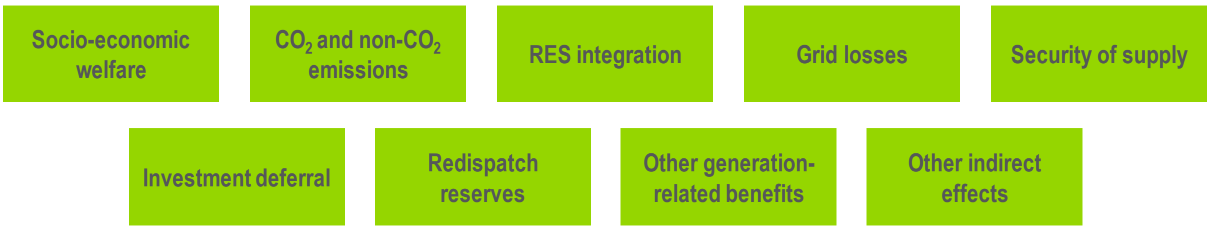


Figure 3-8. Overview of main categories of benefit indicators for hybrid OWPs.

Socioeconomic welfare (SEW)

This indicator evaluates the added socioeconomic benefits of the integration of the project in the European wholesale energy market and is based on short-run marginal costs. The SEW indicator reflects market integration of the European power system. According to the definition under the ENTSO-E CBA guideline for grid development projects, this indicator includes:

> "… in the context of transmission network development, [is] the sum of the short-run economic surpluses of electricity consumers, producers, and transmission owners. The indicator reflects the contribution of the project or investment to increasing transmission capacity, making an increase in commercial exchanges possible so that electricity markets can trade power in a more economically efficient manner. It is characterised by the ability of a project or investment to reduce (economic or physical) congestion."[288]

[288] Draft *3rd ENTSO-E Guideline for CBA*

Through its definition on a societal – transmission level, it captures certain generator-related costs, such as system RES integration costs that are not part of CAPEX or other benefit indicators. These captured generator-related costs include costs of market integration, reduction of energy costs for substitution of energy sources in the market by cheaper (i.e. RES) sources, costs of energy generation, and other market-aspects aspects, such as improved market efficiency and effects on operational costs of the system. The SEW indicator is an important parameter to measure the impact of the project on society and the key stakeholders in the energy market through combining consumer and producer surpluses and congestion rents. It is inherently monetised in € per year through power market modelling or redispatch studies based on short-run marginal costs.[289]

CO_2 emissions variation

The cost of CO_2 emissions is already included in the SEW indicator through the EU ETS price linked to the operation and dispatch of power plants. However, the full impact of CO_2 emissions is not completely captured by the EU ETS price. This separate indicator, as presented under the ENTSO-CBA Guideline, explicitly considers:

> “the change in CO_2 emission due to a new project or investments and in divided into two parts: the pure CO_2 emission in tons and additionally the societal costs in €/year.”

This indicator is quantified through saved tonnes of CO_2 emissions per year and can be expressed in monetary terms as well. The former can be obtained through the market and redispatch modelling conducted for the SEW indicator. Care should be taken with the latter since the CO_2 emission variation is partly monetised within the SEW indicator through the EU ETS price. This indicator should only reflect the additional societal cost of CO_2 emissions that are not captured through the SEW indicator in case the EU ETS would be too low to completely reflect the costs to society. CO_2 emission variation is an important factor to achieve the European climate targets and should be included as a separate indicator for hybrid OWPs.

Greenhouse gas impacts are also adopted under the cross-border RES CBA guidelines.

Non-CO_2 emissions

Next to the direct variation in CO_2 emissions, non-CO_2 emissions could be avoided by the integration of the project in the European energy market. These emissions reflect pollution through other direct emissions such as particulate matter, SO_X, and NO_X or through indirect processes.[290] Non-CO_2 emissions are expressed quantitatively in tonnes per year of non-CO_2 emissions. They could be monetised through a cost parameter determined through subjective assessment or benchmarking.

RES integration

RES integration reflects the benefits of increasing or making better use of (i.e. reduction of curtailment) renewables in the system as an important factor to achieving European climate targets. This indicator need to be reported separately from the SEW and CO_2 emission variation indicators as RES integration is a main driver for reducing CO_2 emissions in the European power system.[291] RES integration is a benefit presented differently for the different perspectives of the CBA.

Transmission perspective (ENTSO-E CBA Guideline[292])

The ENTSO-E CBA Guideline defines RES integration as:

[289] Draft *3rd ENTSO-E Guideline for CBA*
[290] Draft *3rd ENTSO-E Guideline for CBA*
[291] Draft *3rd ENTSO-E Guideline for CBA*
[292] Draft *3rd ENTSO-E Guideline for CBA*

> "[measuring] the reduction of renewable generation curtailment in MWh (avoided spillage) and the additional amount of RES generation that is connected by the project".

It recommends quantifying this indicator either through assessing a reduction in curtailment of renewable energy resources through the project, expressed in MWh per year, or through the MW of RES that would be additionally connected through the project.[293] The indicator can be quantified through power market and redispatch simulations. This representation does not yet include the cooperation effects of cross-border generation assets as part of hybrid OWPs.

Generation perspective (CBA cross-border RES[294])

In RES cooperation on generation assets, RES integration is considered a cost indicator, reflected through additional redispatch costs and costs for onshore grid reinforcement due to additional RES capacities added to the system. From a generation perspective (particularly for cross-border RES projects), RES integration should account for benefits related to the:

> "use of RES potential in one Member State," "impacts of changes in wholesale market prices on support costs for hosting country," and "RES target contribution."

Looking at a system perspective, the first two (use of RES potential between Member States and the impact on support costs) focus on the redistribution of societal cost and benefits (see CBCA in section 3.2.3). Cost of support and the impact on Member States is already covered and discussed under the cost indicators and it is recommended to be excluded from the societal CBA. An important consideration of RES integration is the contribution to RES targets, expressed in share of RES in electricity production. From a system perspective, this could be measured as the contribution to European RES targets and could be defined through power market modelling. For RES target contributions to individual Member States, the cooperation mechanism and potential agreement around statistical transfers will come into play, which is part of the CBCA discussion.

Grid losses

The ENTSO-E CBA Guideline defines this benefit indicator as reflecting "*the changes in transmission system losses that can be attributed to a project.*"[295] This indicator captures the benefit of increased energy efficiency. It could be highly impacted by hybrid OWPs with an interconnection component. Contribution to the reduction of grid losses, expressed in MWh per year, can be quantified through network studies and could be monetised through marginal cost values. Care should be taken with grid losses that are already inherently included in demand patterns in power market modelling, part of the SEW indicator, as to avoid double counting.[296]

Security of supply

Improving security of supply is a key indicators under the ENTSO-E CBA Guideline within the TEN-E process. Large-scale grid development projects could have a substantial impact on security of supply. Security of supply is reflected and measured on multiple timescales as captured by the indicators in the ENTSO-E Guideline for system adequacy, flexibility, and stability:[297]

The ENTSO-E Guideline specifies the evaluation of centralised storage devices on transmission systems, both planned by TSOs or commercial parties.[298] This evaluation would in particular focus on

[293] Draft *3rd ENTSO-E Guideline for CBA*

[294] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

[295] Draft *3rd ENTSO-E Guideline for CBA*

[296] Draft *3rd ENTSO-E Guideline for CBA*

[297] Draft *3rd ENTSO-E Guideline for CBA*

[298] Draft *3rd ENTSO-E Guideline for CBA*

the system benefits the storage unit can bring, including adequacy, flexibility, balancing, and stability services.

- **Adequacy to meet demand:** Adequacy assesses whether "*power is available in the system and can be physically delivered to consumers at any time, including under extreme conditions*."[299] It is expressed quantitatively as lost MWh per year (expected energy not served EENS) and can be calculated using power market modelling with Monte Carlo analysis allowing to cover sufficient system conditions. Monetisation of adequacy could be performed through VoLL (€ per MWh lost). However, there is not a single common methodology to determine the VoLL as it depends on various factors, including regional differences and customer mix.

  Adequacy impacts are also adopted under the cross-border RES CBA guidelines in line with the approach described under the ENTSO-E Guideline.

- **System flexibility benefit:** System flexibility measures the power system's ability to balance operation in the presence of high levels of variable renewable generation through flexibility services including automatic and manual frequency restauration reserves (aFRR and mFRR) or replacement reserves (RR).[300] This indicator is important for cross-border interconnection projects including hybrid OWPs, as aFRR, mFRR and RR can help balance variable renewable generation over a larger region across different control areas. The ENTSO-E CBA Guideline defines indicators to capture system flexibility benefits as *Balancing energy exchange (aFRR, mFRR, RR)*, which is expressed on a defined scale, and *Balancing capacity exchange/sharing (aFRR, mFRR, RR)* which is expressed in qualitative terms. The latter is not yet fully defined under the ENTSO-E Guideline and care should be taken with the definition of the former to avoid double counting.

  Balancing energy exchange is currently not yet monetised or quantified as an indicator, since there is no objective or complete set of data or assumptions available at this stage. In addition, platforms for balancing serves either do not exist or are not consolidated in each control area, limiting data availability for benchmarking.[301] ENTSO-E is developing this indicator. Due to the potential high benefit from hybrid OWPs on system flexibility we recommend to further quantify and monetise this parameter and to monitor the further developments of this indicator by ENTSO-E.

- **System stability benefit:** The stability indicator is defined under the ENTSO-E CBA Guideline as: *"the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance."*[302] There is no clear quantification or monetisation methodology presented in existing CBA approaches due to the complex and time consuming modelling required to capture stability benefits. Due to the uncertain effects of hybrid OWPs and the complex tools required, we recommend leaving this indicator out of the CBA.

Investment deferral

The investment deferral indicator captures the avoided or deferred investment costs due to the project for upgrading and expanding the existing grid or investing in generation assets to ensure security of supply levels are maintained. This only covers deferred or avoided grid investments under the ENTSO-E CBA Guideline.[303] However, for hybrid OWPs, the additional generation component brought into the system and any upgrading or investment costs this new generation can avoid in the current generation portfolio (e.g. phasing out of gas plants) needs to be considered. This is inherently a monetised indicator, reflecting the deferred or avoided costs as brought forward by project

[299] Draft *3rd ENTSO-E Guideline for CBA*
[300] Draft *3rd ENTSO-E Guideline for CBA*
[301] Draft *3rd ENTSO-E Guideline for CBA*
[302] Draft *3rd ENTSO-E Guideline for CBA*
[303] Draft *3rd ENTSO-E Guideline for CBA*

promotors or obtained through benchmarking. This indicator strongly links to the definition and scope of the project and the counterfactual. The counterfactual should include the investment costs that could be deferred by the hybrid OWP to ensure transparent project comparison.

Redispatch reserves

The ENTSO-E CBA Guideline defines this indicator as the *Reduction of Necessary Reserve for Redispatch power plants.*[304] This indicator reflects the saving in redispatch costs that could occur when the project enables the use of cheaper generation units for redispatch.

Redispatch simulations result in the maximum hourly power obtained for redispatching and as indicated by the ENTSO-E CBA guideline can be monetised (EUR per year) through a cost parameter determined through statistical analysis of power plant reserve cost.[305] Hybrid OWPs potentially connect large shares of renewables to at least two markets, increasing market integration and potentially increasing sharing of cheaper redispatching reserves.

Other generation-related benefits

From a generation perspective, hybrid OWPs might give rise to some specific RES-related system benefits such as additional RES expansion that would otherwise not have been realised. This benefit, however, should be captured by the *RES integration* indicator but will be impacted by the choice and configuration of the counterfactual.

Other indirect effects

Introducing a large-scale project in the European power system might additionally result in a whole range of indirect effects. For these indirect effects, the cause of this effect is mostly indirectly relatable to the project or is beyond direct European system level impacts. Moreover, these recorded benefits have low relevance for calculating cost-benefit compensation for hybrid OWPs and are difficult to (objectively) monetise or quantify. We discuss some of these effects below. We recommend excluding these indicators from the CBA. If a project promotor, however, has good qualitative rationale or clear quantification or monetisation approaches, they could be added to the CBA of the project. Under the CEF, a statement on some indirect effects is required for the CBA.

- **Residual environmental, social, or other impacts:** The ENTSO-E CBA Guideline defines categories for residual impact that can be defined by the project promotor to capture any other benefits that the project might bring:[306]
    - Social benefits could include any positive or negative effect on, for example, public acceptance, tourism, or visual impact. This could be quantified through the number of dune crossings from onshore landing points of the project.
    - Environmental benefits could include any positive or negative effect on landscape, environment, or local fauna and flora. This could potentially be quantified through the length of cables running through nature sensitive areas, number of offshore substations, or offshore wind turbine grounding points.
- **Air quality:** Reflects any effects on local or system air quality due to the project. This indicator has low relevance in the context of hybrid OWPs as they introduce renewable generation into the system. Although indirect, hybrid OWPs could push certain technologies of power plants out of the market potentially resulting in localised air quality and local pollution improvements. However, it is difficult to assess which effects will be directly attributable to the project.

[304] Draft *3rd ENTSO-E Guideline for CBA*
[305] Draft *3rd ENTSO-E Guideline for CBA*
[306] Draft *3rd ENTSO-E Guideline for CBA*

- **Innovation:** A parameter stipulated under the CEF as indicated in the cross-border CBA study. Innovation reflects the extent a project includes or advances innovative technologies compared to the existing state of the art.[307] This could include technological innovations, such as effects on the technology learning curve or technology readiness levels (TRL) of technologies, or effects on supply chain innovations resulting from the project. This links to the effects on modernisation of the energy system and competitiveness of the European economy globally. It is difficult to assess what innovative benefits would occur for European society as technological developments and supply chains are mostly transnational.

- **Job creation:** Reflects the benefits of the project to the economy. Within the system-level CBA this would mostly include job creation in countries where assets will be built. However, most cross-national effects likely depend on value chain. The relevance of this indicator for European society is low as jobs in the field of hybrid OWPs and supply chains of offshore developments and their assets are international.

Assessment

The CBA assessment in existing approaches generally recommends monetising indicators as much as possible to perform a societal NPV assessment through discounted cash-flow modelling. For non-monetised indicators a multi-criteria analysis could provide insights to the added benefits of the project beyond cost.

In terms of the parameters of the NPV assessment, we recommend using a societal discount rate of 4% and ensuring zero residual value at the end of the project. Regarding the economic lifetime of components, the ENTSO-E CBA Guideline recommends 25 years. The economic lifetime should allow consideration of the project's benefits and costs and allow the project to reap any benefits or costs related to repowering or upgrading. The economic assessment period should reflect the project lifetime of the different technologies within hybrid OWPs.

3.2.2.6 Recommendations and guiding principles for a CBA of offshore hybrid projects

This section formulates guiding principles for a CBA for hybrid OWP based on the analysis in the previous sections.

General recommendations and guiding principles

- Focus on a societal CBA rather than project CBA to capture the overall costs and benefits of the project to European society. After a positive CBA, the analysis can move towards a CBCA and project CBAs for the different components.

- Build on existing CBA processes as much as possible.

- An approach of a comprehensive CBA framework or a coordination of existing approaches (as to not double count cost and benefits) could be considered, with a potential modular approach depending on project setup.

- Position the hybrid OWP as a strategic project that contributes to European grid development and that can take part in the TYNDP process. Alternatively, Member States could, outside of the centralised TYNDP process, decide on cooperation and pushing forward hybrid OWPs if this fits within their energy strategy, regardless of the outcomes of the centralised process.

[307] Navigant and EY, 2019. Support in the development of the framework for evaluation, identification, selection, eligibility and support of Cross-Border Projects in the field of renewable energy under the Connecting Europe Facility (CEF) – Final report prepared for the European Commission DG Ener (ENER/C1/2018-554).

- Hybrid OWPs without hardware cooperation (cases 1 and 2 in section 1) can follow the guiding principles as set out in the cross-border RES CBA study to capture societal costs and benefits. These configurations only a generation (or storage) project with a grid connection.

Recommendations along framework defined above

Project definition

- Define a clear project scope in space and time to avoid overly complex quantification methods and to ensure identified system impacts can be directly assigned to the project.

- Consider an approach to deal with phased investments throughout a single offshore hybrid project.

Data, scenarios, and boundary conditions

- Follow guidelines of existing CBA approaches in terms of multiple scenarios and sensitivity analysis to ensure robustness of the CBA results.

- Define an unambiguous set of energy system scenarios for project comparison.

- Clearly define and map boundary conditions of the project including governing market design, cooperation mechanism, and grid delivery model due to their impact on the CBA results.

Counterfactuals

Care should be taken in the definition of counterfactuals

- Hybrid OWPs with a generation and interconnection component might largely impact power system operation. An appropriate counterfactual to realistically capture the effects of cross-border hybrid configurations might be an alternative configuration of the project, with currently established technologies (more radial RES connections and separate interconnectors), or the system with or without the project.

- The selected counterfactual and its boundary conditions might vary from the boundary conditions of the offshore hybrid projects jeopardising the common base of comparison.

Cost and benefit indicators

- Combine effects on European society from generation and transmission components of hybrid OWPs in a holistic societal approach.

- Monetise indicators as much as possible to enable transparent project comparison.

- Monetisation of indicators should be performed as much as possible by a single objective party, such as ENTSO-E, ACER, or national government agencies to ensure process consistency. However, ENTSO-E, ACER, or the EC would have to take decisions on monetisation options that are subject to interpretation and could be contested by impacted stakeholders.

- Project promotors could introduce data on costs and missing benefits if they have access to better quality data or evaluation methods for their specific projects.

- Focus on a compact set of indicators that capture the largest systemic impact on SEW, i.e. indicators that capture the direct system effects of the project.

- Unambiguously define the scope of each indicator to avoid double counting generation and transmission costs and benefits.

- Distinguish between scope of the societal CBA (system perspective – European societal perspective) and CBCA-related benefits at Member State and TSO level.

- Perform reporting of costs and benefits at an EU-level and (if modelling tools allow) on a bidding zone or Member State level. The latter will facilitate discussions on the CBCA.

- Support ENTSO-E in the development of a quantified and ideally monetised indicator for system flexibility benefits, which is a potential high societal benefit that could be provided by cross-border offshore hybrid projects.

- Table 3-11 presents the recommended indicators for the societal CBA for hybrid OWPs.

- Include indirect project-specific effects if project promoter has a clear rationale, set of data, or information to support this, for example, the effect of the project on innovation, residual environment, or social impacts.

Assessment

- Follow guidelines of existing CBA approaches in terms of a societal discount rate of 4% and use an NPV assessment for monetised indicators.

- Use technology-specific economic lifetimes to ensure capturing the full lifetime benefits of the project and its components and include upgrades and reinvestments if required during assessment period.

- Adopt zero residual value approach.

Table 3-11. Overview of relevant cost and benefit indicators for hybrid OWPs.

Cost and benefit indicators	Description	Reporting scope of results from system-based analysis	How to monetise or quantify?
CAPEX	CAPEX of the project related to grid permitting and licensing, site (pre-)development, groundwork, design, equipment installation, temporary structures, equipment purchasing, financing costs, decommission for both infrastructure and generation components, and relevant grid connection and onshore grid investments.	Project-level Europe (system-level)	Inherently monetised but for some assets and components benchmarking might be required
OPEX	Costs related to O&M of the project including generation and infrastructure components and relevant grid connections and onshore grid investments.	Project-level Europe (system-level)	Inherently monetised through O&M cost data or through fixed percentage of yearly CAPEX but benchmarking might be required
Socioeconomic welfare	Consumer surplus, producer surplus, and congestion rents.	Europe (system-level)	Inherently monetised through power market modelling and redispatch modelling based on short-run marginal costs
CO_2 emissions variation	CO_2 emissions through dispatch of power plants.	Europe (system-level) Bidding zone (Member State) level	Quantified through CO_2 emissions from power market modelling (tonnesCO_2/year) Monetised through cost parameter (EUR/tonne) reflecting difference between societal costs of CO_2 emissions and EU ETS price
Non-CO_2 emissions	Non-CO_2 emissions through dispatch of power plants.	Europe (system-level) Bidding zone (Member State) level	Inherently quantified through tonnes/year based on power market modelling and redispatch simulations. Monetisation through subjective cost parameter or benchmarking

Cost and benefit indicators	Description	Reporting scope of results from system-based analysis	How to monetise or quantify?
RES integration	RES capacity connected (MW) on a system or bidding zone level, or Reduction in RES curtailment (MWh per year) on a system level, or RES target contribution on a system level (share of RES in energy system).	Europe (system-level) Bidding zone (Member State) level	**Capacity connected**: Inherently quantified through MW RES connected through the offshore hybrid project. **Curtailment**: Inherently quantified through MWh per year only at system level through power market modelling. Theoretically, they could be derived and compensated ex-post on an aggregated level. An ex-ante allocation is not possible. **Target contribution:** Inherently quantified through MWh per year of demand at system and bidding zone level through power market modelling.
Grid losses	Thermal losses due to transport of power not included in the demand profile used for SEW calculation.	Europe (system-level) Bidding zone (Member State) level	Quantified through network studies (MWh per year) and monetised through marginal cost values (€ per year).
Adequacy	Power in the system to meet demand to consumers when required.	Europe (system-level) Bidding zone (Member State) level	Quantified through power market modelling with Monte Carlo simulations (MWh per year). Quantified through the value of lost load (VoLL in €per MWh).
Flexibility	Ability of the power system balance operation in the presence of high levels of variable renewable generation.	TBD, but at least Europe (system-level)	To be developed but of potential high importance to capture full range of benefits of offshore hybrid projects.
Investment deferral	Avoided or deferred investment costs in grid infrastructure or generation - e.g. cost-efficient expansion of offshore (less €/kWh compared to national approach). Can be positive or negative (national infrastructure cost savings).	Europe (system-level) Bidding zone (MS)	Inherently monetised (EUR) through data from project promotors or benchmarking.

Cost and benefit indicators	Description	Reporting scope of results from system-based analysis	How to monetise or quantify?
Redispatch reserves	Reduction of Necessary Reserve for Redispatch power plants.	Europe (system-level)	Quantified through redispatch simulations (max MW per hour for redispatching) Monetised (€ per year) through a cost parameter.
Other indirect effects	The project can result in a wide range of indirect effects that are more difficult to capture objectively or in quantitative/monetised terms, such as, innovation, residual environmental, social or other impacts, air quality, job creation, and more.	Europe (system-level) Bidding zone (Member State)	Depending on information of project promoter these indicators could be put forward for inclusion in the CBA either through a qualitative rationale or quantified or monetised through project promoter data.

3.2.3 *Cross-border cost allocation*

3.2.3.1 Introduction

The societal CBA assesses whether a joint (hybrid) OWP is beneficial for society and inherently excludes the distributional effects on impacted stakeholders. It deliberately excludes the question of whether all impacted stakeholders are better off with a project than without it (or compared to its counterfactual). We assume that for most joint (hybrid) OWPs some stakeholders will lose while others win (which will be the case in any cooperation arrangement). The distributional effects of a project to each stakeholder need to be assessed. This serves as a basis for reallocating costs and benefits between stakeholders to ensure that the net benefits identified in the societal CBA are distributed to make the relevant involved stakeholders better off with the project than without it. The key stakeholders experiencing impacts from (joint) hybrid offshore projects are TSOs, the generation asset developer, and Member States (representing their consumers). The approach to formulate CBCA guiding principles includes the key elements described below.

- **Identify main issues when moving from CBA to CBCA:** While the CBCA will be based on the CBA approach; key issues are discussed that need to be addressed to switch from a societal to a stakeholder-specific perspective.

- **Revision of cost-benefit indicators:** The cost and benefit indicators defined in the CBA are revised to capture distributive effects between Member States/bidding zones and stakeholders within Member States.

- **General compensation approaches:** Key options for compensation are discussed, including existing approaches, the issue of conflating costs and benefits of infrastructure and generation asset vs. keeping them separate. In addition, a dynamic approach to the CBCA is discussed.

- **Defining prices for the CBCA decision:** Brief considerations are developed on how to define the prices for compensation in the CBCA.

3.2.3.2 Relevant issues to move from CBA to CBCA

Starting point for the CBCA

Methodologically, the analysis for the CBCA should build on the CBA assessment as much as possible to maintain coherence with the main identified effects. The project definition, data, scenarios, and boundary conditions assumed in the CBA should not be changed. The net values of the cost and benefit indicators identified under the CBA will be used as a starting point for the distribution of costs and benefits in the CBCA.

Scope of CBCA

The number of stakeholders involved in the CBCA should be limited to avoid prohibitive transaction costs if stakeholders with minor impacts are included. For instance, a project may have minor benefits for a Member State beyond those adjacent to the project but including them may unnecessarily increase the complexity of the CBCA. ACER recommends for infrastructure CBCAs including stakeholders who receive at least 10% of the net benefits.[308] This allows for including the main impacted parties while avoiding prohibitive transaction costs. However, we suggest keeping this rule flexible in the context of RES cooperation so Member States are free to decide who to include in the

[308] See also PROMOTioN project 2019: D7.4 Economic framework for a meshed offshore grid. Available at:https://www.promotion-offshore.net/fileadmin/PDFs/D7.4_Economic_framework_for_a_meshed_offshore_grid.pdf

cooperation, regardless of how large the share of impact. Naturally, the involved parties will have an interest in excluding stakeholders from the CBCA that experience minor impacts.

Boundary conditions

The range of boundary conditions and support scheme design options discussed in this report will have major impacts on the cost-benefit distribution and compensation requirements. First, the market arrangement will impact revenues for project developers and for TSOs. In the OBZ, revenues are effectively transferred from the project developer to the TSO and so support costs will increase. This shift in costs and benefits compared to the HZ solution needs to be reflected in the CBCA.

The process for site selection and the grid connection regime also has major impacts on the initial distribution of costs and benefits and the need for compensation, as the related costs will either be borne by TSOs and so appear in grid tariffs or will be included in the bid in an auction and be financed by the support scheme and thus levy payers. This has implication on which party needs to be compensated (e.g. TSOs or levy scheme).

The CBCA is heavily impacted depending on whether hydrogen is included in the project or not. This concerns costs for the electrolyser and the need to distribute them; cost could be borne by the Member States or be refinanced via market revenues. The extent to which this is possible depends on the hydrogen market (e.g. whether a hydrogen obligation exists or not) and on the applied levy, fee, and tax regime for the hydrogen production. The benefits also would be heavily impacted, depending on how hydrogen production and consumption count towards national RES shares. Since the impacts of including hydrogen into the project and thus into the CBA and CBCA depend on many factors outside the support scheme and have yet to be decided on by Member States, we exclude the specific case of hydrogen from further CBCA considerations.

3.2.3.3 Cost and benefit indicators for the CBCA

To capture distributional effects between the cooperating Member States and stakeholders within Member States, the cost and benefit indicators from the societal CBA need to be adjusted. This section examines whether/how each CBA indicator would have to be adapted to be applied for the CBCA. The CBCA decision for hybrid OWPs will be a negotiation outcome between Member States who should be flexible to highlight certain cost/benefit impacts of a project that they deem significant. They may also exclude indicators that they agree are less relevant to reduce the complexity of the analysis and the negotiation. In addition, some impacts may not be quantifiable but may still be perceived as significant by Member States, so they may include these aspects into the negotiation on the CBCA.

CAPEX/OPEX

The societal CBA is indifferent to who pays for the CAPEX and OPEX, that is, which share of the entire joint hybrid OWP is refinanced through congestions rents, grid tariffs, market revenues, or support schemes. For the CBCA, these elements need to be differentiated to account for the impacts on TSOs, consumers and levy payers:

- CAPEX/OPEX for infrastructure (interconnector and potentially grid connection – depending on grid connection regime and onshore grid reinforcement), are initially borne by one or more TSO. They are refinanced via congestion rents for each TSO and network charges in the respective bidding zones/countries (to be defined in an OBZ).[309]

[309] The TEN-E Regulation (EU) No 347/2013 stipulates in Art 12 to focus on “the efficiently incurred investment costs, which excludes maintenance costs,“ thus seeks to exclude part of the OPEX as those are socialised through grid tariffs and are difficult to predict for the project.

- CAPEX/OPEX for generation assets (with/without grid connection depending on grid connection regime), are initially borne by the project developer and refinanced via market revenues and potentially support scheme payments.

Socioeconomic welfare (SEW):

This indicator represents the "sum of the short-run economic surpluses of electricity consumers, producers, and transmission owners (congestion rent)."[310] For the CBCA, this indicator should be defined and assessed as in the CBA, but it needs to capture the impacts for each of the named stakeholders and per bidding zone. It would identify, per bidding zone, the effects on wholesale market prices (where decreasing prices are the consumer benefit and the reduced producer surplus) and congestion rents (the benefit for the TSOs). However, the change in wholesale market prices creates an ambivalent impact for Member States. The decreasing electricity price increases consumer surplus but it also leads to increasing support costs whenever sliding premium schemes are applied (in asymmetric CfD and in symmetric sliding premium). We expect the impacts of single cooperation projects to be limited on the wholesale market price and expect that this indicator plays a less important role for the CBCA compared to the CBA.

CO_2 emissions (CO_2 emissions through dispatch of power plants)

Although relevant for the CBA, this indicator may be irrelevant for the CBCA as CO_2 emissions in the electricity sector are covered in the EU ETS (and thus are not Member State-specific). If the full (cost) impact of emissions on society are not be captured through the governing EU ETS price (i.e. the EU ETS price might be too low to compensate the full effect of CO_2 emissions), they may be reincluded in the CBCA.

Non-CO_2 emissions

These are defined in the CBA as change in non-CO_2 emissions through dispatch of power plants. For the CBCA these may be defined more generally in terms of emissions impacts including sound emissions as well landscape and other environmental impacts These will be difficult to quantify or even monetise but may be considered when negotiating the transfer price (see below).

RES integration

This indicator (as defined in the CBA), could be expressed as "RES capacity connected (MW) on a system or bidding zone level," "Reduction in RES curtailment (MWh per year) on a system level," or "RES target contribution on a system level (share of RES in energy system)." For the CBCA for a joint hybrid offshore project, the key aspects are the effects on each bidding zone in terms of curtailment (as lost value) and the RES statistics resulting from the generation asset, which is the key transfer component in the cooperation mechanisms as defined in the RED II.

Grid losses

This indicator is defined as the thermal losses due to transport of power. We recommend excluding this indicator for the CBCA, as we expect no monetisable effects of hybrid offshore projects compared to radially connected systems.

[310] 3rd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects, Draft version, 15 October 2019.
https://eepublicdownloads.blob.core.windows.net/public-cdn-container/clean-documents/tyndp-documents/Cost%20Benefit%20Analysis/191023_CBA3_Draft%20for%20consultation.pdf

Security of supply

- System adequacy is the power in the system to meet demand to consumers when required. An additional hybrid OWP increases the adequacy in the hosting Member State. This benefit is refinanced via market revenues in the host Member State and potentially additional support costs. It may be quantified based on the CBA as energy not served.

- System flexibility is the ability of the power system to balance operation in the presence of high levels of variable renewable generation. Flexibility increases in the case interconnector functionality is included in the project and it will be impacted by the additional RES capacity added to the system as part of the project. If the impacts on system flexibility are significant for any of the cooperating Member States, the effect could be quantified and compensated once the indicator is further developed in ENTSO-E's CBA guideline. Currently, the indicator is assessed qualitatively and could play into the negotiations on transfer prices.

Investment deferral

This indicator refers to avoided or deferred investment costs as a result of the project. For the CBCA, we recommend focussing on the infrastructure part of the project, as for the generation asset the deferred investments are actually the goal of the renewables cooperation, i.e. no compensation is needed.

In the CBA, investment deferral also includes the cost-efficient expansion of offshore (less €/kWh compared to a national approach), which in the cooperation mechanisms relates to the "use of RES potential." The use of RES potential in one Member State for cooperation may need to be compensated by another cooperating Member State. This indicator is difficult to quantify, but if deemed significant by any host Member State involved in the cooperation, it may be used in the negotiation on transfer prices in the CBCA.

Redispatch reserves

In the CBA, this indicator relates to the "reduction of necessary reserve for redispatch power plants" and is what usually is referred to as "system integration costs/additional redispatch" in the Cooperation Mechanisms. It needs to be captured according to the methodology described in the CBA, but per bidding zone (per cooperating Member State) for the CBCA.

The discussion of each indicator has shown that most cost-benefit indicators can be assessed as defined in the CBA for the CBCA, albeit capturing the effects per impacted TSO or bidding zone (i.e. Member State in most cases). Some indicators need to be differentiated to capture the distributive effects per impacted party. Based on the discussion of the CBA indicators above and how they would convert for the CBCA, the following indicators should be considered. The order is partially changed compared to the CBA as the indicators are sorted by impacted party.

Table 3-12. Overview of cost and benefit indicators for CBCA based on CBA approach.

Cost and benefit indicators	Impacted parties	Description of impact
CAPEX and OPEX of infrastructure element	TSO	One or more TSO pre-finance the infrastructure asset, connection to shore and onshore reinforcement.
Congestion rents (part of SEW in CBA)	TSO	TSOs generate revenues from congestion, albeit to different extent for each TSO. Impact on each TSO also depends on market arrangement (OBZ vs. HZ).
Additional redispatch (redispatch reserves in CBA)	TSO	TSOs may increase or decrease redispatch as a result of project. Redispatch costs is refinanced via grid tariffs.
System flexibility (part of security of supply in CBA)	TSO	Flexibility increases in the case interconnector functionality is included in the project and it is impacted by the additional RES capacity added to the system as part of the project.
Investment deferral – infrastructure	TSO	Avoided or deferred investment costs in grid infrastructure or generation as a result of the project.
CAPEX and OPEX for generation asset	Generation project developer	Project developer pre-finances the generation asset.
Market revenues	Generation project developer/operator	Project generates income from selling at electricity exchange (or other marketing routes). Income depends on market arrangement (lower in OBZ compared to HZ).
Support scheme payments	Member States (their levy/taxpayers) and project developer	Member States make support scheme payments based on a pre-agreed share.
RES target statistics (part of RES integration in CBA)	Member State	Member State where production asset is located increases its national RES share according to electricity production.
Effects on wholesale market price (part of SEW in CBA)	Member State (their consumers)	Cooperation project may decrease or increase wholesale market prices in each of the bidding zones, thus impacting cost of electricity for consumers and reversely support costs for existing RES plants in sliding premium systems.
(Non-)CO_2 emissions	Member State	Project may increase or decrease emissions in each Member States.
Use of RES potential (part of investment deferral in CBA)	Member State	The hosting Member State loses RES potential for purely national RES deployment.

3.2.3.4 General compensation approaches

Stakeholders bearing costs but not receiving the corresponding benefits need to be compensated and those receiving significant benefits should contribute to the compensation. This section discusses existing approaches to compensation, the option to mix or keep compensation streams separate, and how to approach the CBCA from a dynamic perspective.

Existing approaches for generation and infrastructure assets

TEN-E and the practice in cooperation in the context of the RED I and II are starting points for compensation approaches for stakeholders involved in joint hybrid OWPs. When allocating costs and benefits for cooperation projects as defined in the RED (I and II) (i.e. generation assets) Member States agree to cooperate and identify the key cost and benefit elements of cooperation. Subsequently, Member States agree on a compensation model and on the specific allocation of costs and benefits. The allocation of costs and benefits in RES cooperation has so far been based on a selective and pragmatic approach to identify the key cost and benefit elements to be addressed.[311] The compensation is seen as the result of a negotiation process between the involved Member States. There are several reasons for the pragmatic and negotiation-based approach:

- The value of a key benefit from cooperation on generation assets (the RES target statistics), is not straightforward to determine and depends on various factors such as the cost of alternative options for the cooperating Member States (i.e. national RES deployment, statistical transfers, cooperation with other Member States, the EU RES financing mechanism, and even noncompliance with the RES target). Compensation for the transfer of RES statistics can hardly be monetised in a straightforward or purely technical manner.

- There is no common and established CBA methodology to apply.

- The transaction cost for a full quantification of costs and benefits would be high (and potentially prohibitive).

- The compensation for RES generation assets happens between governments and on a political instead of a technical level.

- There are various (political) non-quantifiable costs and benefits, such as the general value attributed to strengthen energy cooperation between Member States, the strategic value of specific technology cooperation.

The approach to reallocating costs is different for cross-border infrastructure assets (when part of the PCI process). The project promoter prepares the detailed technical description and project-specific CBA and submits the investment request to the impacted NRAs, which then transmit the request to ACER and define a coordinating NRA. The NRAs (similar to Member States in the case above) identify the main costs to be allocated, agree on the allocation of the costs, and on specific payments. The NRAs adopt the coordinated decisions and notify ACER. In contrast to cost allocation for generation assets, the CBCA for infrastructure projects is based on a comprehensive CBA, aiming for comparable analysis. The actual compensation is through cash transfers and is implemented by TSOs (and not Member States as in the cooperation mechanisms as defined in the RED I and II).

Mixing costs and benefits vs. keeping them separate

For the generation assets and the transmission assets, different approaches and processes are available to define a CBCA decision. Moreover, the individual components of hybrid OWPs are legally related to the different impacted parties and their respective investment and revenue regime:

- Infrastructure is a core responsibility of TSOs, who refinance their investments via grid tariffs and congestion rents in a highly regulated market. Accordingly, the use of grid tariffs and congestions rents is defined in European and national legislation.

- Generation asset developers operate in a more liberal market context and generally refinance their investments via market revenues (and are free to choose their marketing route and business model) and support scheme payments.

- Member States aim for increasing RES shares and partially use support schemes for that purpose, financed either via levies or via the general budget (i.e. taxes).

[311] Note that cost benefit allocations in the context of the cooperation mechanisms have only been assessed on theoretical levels for joint project and joint support schemes. See for a detailed discussion Klessmann et al., 2014. Cooperation between EU Member States under the RES Directive. https://ec.europa.eu/energy/sites/ener/files/documents/2014_design_features_of_support_schemes_task1.pdf, von Blücher et al., 2018. Design options for cross-border auctions. http://aures2project.eu/wp-content/uploads/2019/06/AURES_II_D6_1_final.pdf

Mixing these investment and money streams may be beneficial as it would allow defining a cooperation package covering the entire hybrid OWP. Bottom-line effects and a bottom-line compensation decision could be envisaged. However, mixing these elements in terms of the concrete compensation payment streams is likely to create multiple legal challenges and may require substantial legal changes in the involved Member States and in EU legislation. For instance, on a national level, grid tariffs usually cannot be used to make support payments to RES generation assets. Likewise, support scheme payments are usually not used to make grid investment (which depend on the grid connection model though). Such a mixing of money streams in the context of a cooperation agreement would contradict the (justified) separation at a national level.

We recommend keeping the streams for costs, revenues, and compensation separate between the involved parties and their respective responsibilities:

- Impacts are mapped for TSO according to their defined responsibilities (infrastructure and system effects) and the respective, existing refinancing mechanisms (congestion rents and grid tariffs).

- Remaining impacts are mapped for Member States concerning their broad responsibilities (e.g. with a view to support scheme payments, RES target statistics, effects on wholesale market price, and the use of RES potential).

The separation of impacts according to each stakeholder ensures a proper use of revenues, support levies, and grid tariffs according to their legal basis. In this approach, the impacted parties compensate or are compensated for the effects related to them. Keeping the money streams and their legal justification separate is advisable in more complex cooperation, i.e. cases 4 and 5 in which infrastructure and generation asset cooperation are combined. In case 3, a pure TSO-led CBCA process is required. Despite this general recommendation, there may be cases (such as cases 1 and 2) in which Member States wish to include considerations like grid integration costs into the definition of a transfer price for RES statistics.

Cooperation between Member States includes a political process and rationales. Although we recommend keeping costs and benefits impacting TSOs directly separate from those relevant for Member States, the overall cooperation on joint hybrid OWPs may be pursued and driven forward by Member States. Even when respecting the separation of costs and benefits according to the different stakeholders, Member States will want to achieve an overall benefit from the cooperation (including both the infrastructure and generation asset components).

The currencies available for compensation are cash payments and RES statistics. Compensation between TSOs will happen for their respective impacts in the form of cash payments and between Member States in the form of cash payments, transfers of RES statistics or a mix of both.

A dynamic approach to CBCA

Analysis of distributional effects and the resulting compensation decision happen before the project is realised and actually unfolds its effects—making it a challenge to define a CBCA. This implies major uncertainties about the realised costs and benefits in a project lifetime. The actual costs and benefits depend on a range of factors, including market price developments and resulting support scheme payments in sliding premium systems. The impacts of a project on each party depend on long-term decisions on how the energy system will be developed towards 2040 and beyond. This includes elements such as:

- Envisaged offshore capacities in Europe and their geographical distribution

- Envisaged interconnector capacities and their geographical distribution

- Share of hybrid projects in these capacities

- Major demand factors such as electrification shares and, more specifically, hydrogen volumes

- The applied market design

Three options are available to approach the challenge of uncertainty in the CBCA: first, accepting uncertainty, a review clause, and rule-based compensation:

- **Accepting uncertainty:** Participating parties may agree to an ex-ante compensation decision and accept the related uncertainties. This may be suitable if the net benefits shown in the societal CBA are significant and all relevant impacted parties can be compensated with a sufficient degree of certainty to be better off with the project than without. This may not result in a pareto-optimal distribution of the benefits but may be a pragmatic solution for reaching binding agreements on cooperation. Ultimately, cooperation on complex projects will depend on the political will to cooperate and the acknowledgement of the strategic value of cooperation.

- **Review clause:** If the uncertainty around an ex-ante compensation decision is perceived to be inacceptable, Member States and TSOs could agree to a review clause (e.g. every 5 or 10 years), which may serve to adjust the compensation decision according to actually realised impacts. However, this approach would create uncertainty around the exact conditions of cooperation for joint hybrid OWPs, which would induce major uncertainties for TSO investments into infrastructure. In addition, this approach may result in increased transaction costs if the analysis and subsequent negotiations have to be repeated throughout the project lifetime.

- **Rule-based compensation (conditional or pro-rata):** Compensation payments may be based on certain rules. One option is to make compensation payments conditional. Certain shares of compensation amounts are paid only if certain effects are observed, e.g. every year or every 5 years up to a defined economic lifetime of the project. The challenge is that over the long lifetime period of infrastructure projects, methodologies to observe effects and boundary conditions may fundamentally change. This in turn could undermine the legitimacy of the initial compensation decision.

Another option for rule-based compensation is to relate the compensation to a pro-rata approach, which (at least theoretically) is established for cooperation on RES generation assets. The share of support costs paid by a Member State results in the respective allocation of RES statistics (e.g. Member State pays 30% of the support costs and receives 30% of the RES statistics). This approach may be considered for the infrastructure part as well with a view to the distribution of congestion rents (e.g. a TSO pays 40% of the investment costs and receives 40% of the congestion rent resulting from the infrastructure investment). However, limiting the pro-rata approach to the support costs (for generation) and investment costs (for infrastructure) would neglect a range of distributional effects (such as electricity market price impacts and the potential need for onshore grid reinforcement). Moreover, support costs for generation assets are not always necessary and are generally expected to decrease; their share in the financing of offshore wind farms becomes less significant and serves less well as an indicator. As a result, the pro-rata approach needs to be adjusted according to the additional effects identified in the stakeholder-specific assessment of project impacts.

A mix of the rule-based compensation and recognising the strategic value of cooperation (and thus accepting some uncertainty) seems advisable. It could imply that for the infrastructure part and the resulting congestion rent the compensation is realised between TSOs. For the remainder of impacts, compensation between Member States could be achieved, initially based on the share of support costs borne by each Member State and a range of additional aspects that Member States deem relevant to determine the compensation. This compensation can be based on the transfer of RES statistics and additional compensation payments. Which solution is advisable depends on the exact cooperation setup and the preference of the involved Member States, so no one-size-fits-all solution is possible. Section 3.2.4 includes various cases and assess what compensation approaches may be suitable for each of them.

3.2.3.5 Defining prices for the CBCA decision

The TSO-related CBCA decision should be limited to the infrastructure assets and compensation should mainly focus on CAPEX and OPEX of the infrastructure asset, the expected congestions rents, and additional (or reduced) redispatch that a TSO may expect due to the project. These cost and benefit indicators can be quantified and monetised in a straightforward manner. The cost of redispatch may be difficult to determine, but it is not based on the willingness to pay of the respective TSO. The outcome of the CBCA decision regarding the infrastructure may depend a lot on the assessment of the individual impacts (the model used, the assumptions) and the assessment approach may be subject to differences between TSOs. However, the final compensation decision appears not to be the outcome of a negotiation, based on individual and even political preferences of the involved TSOs.

The compensation price for the impacts related to Member States is subject to the value attached to qualitative aspects (such as the value of cooperation) and so a result of negotiations between the Member States. The necessary support costs are uncertain in all forms of support as they depend on production and (in sliding premium systems) on the electricity price.[312] But they are inherently monetised and defining a distributional share of support costs may result in the according share of RES statistics transferred to the contributing Member State. This results in an implicit and dynamic price for RES statistics.

However, the lower the required support costs, the less they determine the transfer price for the RES statistics. Especially where Member States cooperate on projects with no support costs, the transfer price will be negotiated based on other cost-benefit considerations. This price ultimately depends on the willingness of the involved Member States to sell or pay. This willingness may be heavily impacted by political preferences and public opinion. The selling Member State may then use the revenues for various purposes, for example, to lower existing levies or finance R&D activities.

For the other relevant cost and benefit impacts (effects on wholesale market price and use of RES potential) significant uncertainties are related to the long-term effects of a project and the monetisable value, especially in the case of use of RES potential. Again, these indicators and their value are likely subject to negotiations between Member States.

The cost-benefit impacts for TSOs should be separated from impacts on Member States. We recommend TSOs focus on the CAPEX and OPEX of the infrastructure asset, the expected congestions rents and additional (or reduced) redispatch. Member States may focus on support costs and RES statistics (and inherently link them or agree on a transfer price based on negotiation) or include other impacts in case they are expected to be quantitatively and politically significant (e.g. effects on wholesale market price and use of RES potential), which determine a Member States willingness to pay.

3.2.4 Case studies

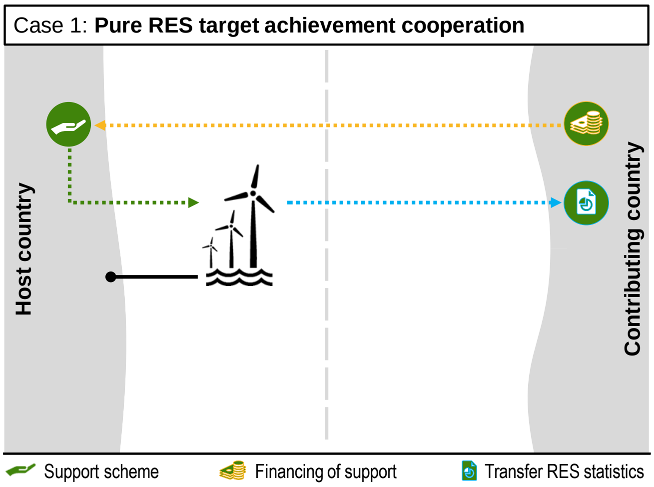
In this section, we apply (at a high level manner; without actual quantifications) how the suggested CBCA approach would work for the different project setups defined in section 3.1.3. We focus the case studies on the CBCA and not on the CBA, as the cases do not reveal major differences in terms of how the CBA would be conducted.[313] In addition, the high level cases do not have detailed project specifications that allow detailed evaluation of indicators or the definition of a counterfactual. By contrast, the CBCA implementation approach may differ substantially between the cooperation cases, providing conceptual insights for the CBCA. For each case, we describe in qualitative terms which high level impacts may occur for the involved stakeholders and subsequently, how the costs and

[312] This is different for upfront investment aid which provides certainty for Member States at the time an auction/a tender has been successfully implemented.

[313] This approach implies the hypothetical assumption that each of these projects has net benefits compared not being built at all and compared to similar alternative project setups. This assumption does not represent an actual CBA outcome for these cooperation cases.

benefits may be redistributed to achieve buy-in for the cooperation case from stakeholders. Where applicable, we discuss implications of the case on the cooperation software.

3.2.4.1 Case 1: RES target achievement



In this setup, no interconnector functionality is part of the cooperation project and the OWP is in the Member State it is connected to. This case represents a joint project according to Article 9 of the RED II and no TSO-involvement is required in the cooperation, so it is purely a Member State cooperation. A hypothetical example of this cooperation case may be Luxembourg paying an amount to the Netherlands to receive RES statistics from a specific OWP. The Netherlands would then transfer these statistics to Luxembourg.

Cross-border cost allocation

In the CBCA, the cost and benefit components are initially limited to the Member State where the offshore wind farm is located. This concerns mainly support costs (if required), the use of RES potential in the host Member States, and RES statistics. The host country may experience additional redispatch (or required redispatch reserves) and grid reinforcement costs because of the OWP, implying additional negative values for the indicator CAPEX of infrastructure (Table 3-13). The latter set of costs is initially related to the TSO in the host country (we suggested above that costs and benefit streams are maintained with the respective stakeholders where they occur). However, in case 1, the TSO of the contributing Member State is not necessarily experiencing any impacts and there is no reason to include this TSO in the CBCA. If the host country deems necessary, some of its TSO-related costs could be reflected in the transfer price for the RES statistics (i.e. compensated between Member States rather than between TSOs).

Table 3-13. Impact on relevant parties for the CBCA in case 1.

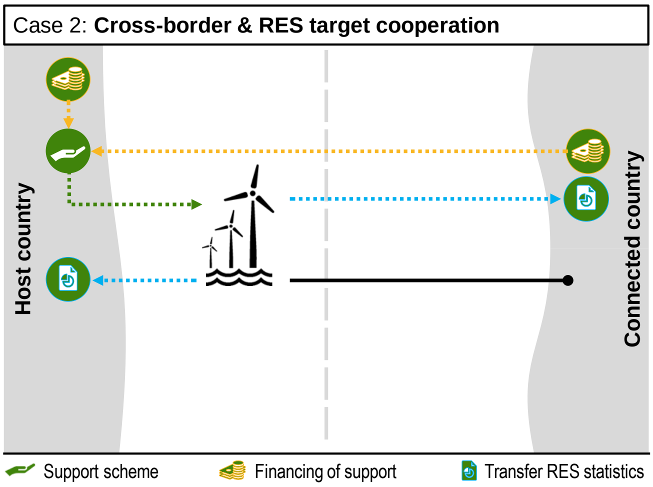
Cost and benefit indicators	Impacted parties	Host country	Contributing country
CAPEX (and OPEX) of infrastructure element	TSO	0	0
Congestion rents (part of SEW in CBA)	TSO	0	0
Additional redispatch (redispatch reserves in CBA)	TSO	(-)	0
System flexibility (part of security of supply in CBA)	TSO	(-)	0
Investment deferral – infrastructure	TSO	(-)	0
CAPEX and OPEX for generation asset	Generation project developer	(-)	0
Market revenues	Generation project developer/operator	(+)	0
Support scheme payments	Member States (levy / tax payers)	(-)	0
RES target statistics (part of RES integration in CBA)	Member State	(+)	0

Effects on wholesale market price (part of SEW in CBA)	Member State (their consumers)	(+) (decrease of prices)	0
(Non-)CO_2 emissions	Member State	(+)	0
Use of RES potential (part of investment deferral in CBA)	Member State	(-)	0

Each of the impacts occurring in the host country may be perceived as occurring in the opposite way in the contributing country as the contributor avoids building such capacity domestically. This would imply a counterfactual in which the project is compared to a similar project (i.e. a project without cooperation). However, this then omits the total value of costs and benefits and the CBCA requires not just net benefits to be shared but all relevant costs, benefits, and total values as well.

The key aspects to determine for the participating Member States are the share of support costs to be borne by the contributing Member State and the resulting transfer of RES statistics (if 20% of support costs are paid for by the contributing country, it would receive 20% of the RES statistics). In case no support costs are required or in case the host country values the use of its RES potential or the grid-related impacts, the transfer price may ultimately inform the willingness to sell of the host Member State.

3.2.4.2 Case 2: Cross-border and RES target achievement



In this setup, no interconnector functionality is part of the cooperation project. However, the OWP is located in the EEZ of another Member State than the one it is connected to. This represents a joint project according to Article 9 of the RED II and no TSO-involvement is required in the cooperation in terms of CBCA. Nonetheless, the TSO of the connected Member State would have to gain the right to finance and build part of the connection to shore which is located in the adjacent EEZ.

A hypothetical example of this would be an OWP located in Germany's EEZ, but connected to the Netherlands (or Denmark).

Cooperation software

Case 2 appears to imply only a minor change in terms of the CBCA compared to case 1, i.e. the shift from a project within a single EEZ to a project spanning across two EEZ. However, this has implications for the cooperation software and for the CBCA. First, the default case is that the OWP would be part of the host countries support scheme (regardless of whether support is actually needed or not), including its site selection process and grid connection regime (even though this would not guarantee a cross-border grid connection yet). Second, the RES statistics would initially stay within the host Member State of the OWP, despite being connected to another. This case allows for two options:

- **Option 1:** Keep the OWP in the host country's support scheme
- **Option 2:** Embed the OWP in the support scheme of the connected country

Option 1: Keep the OWP in the host country's support scheme

The host Member State would provide the support scheme details, but various elements would have to be coordinated:

- **Site selection:** The host Member State provides the centralised site selection and pre-investigation. An open-door scheme spanning across two Member States is impractical.
- **Grid connection:** The installation would be connected to the cooperating Member State; both Member States would have to agree on the applied grid connection regime, which in turn would have impacts on the level of support costs. It is reasonable to use the rules of the grid connection regime of the Member State to which the OWP is connected (maintaining established grid connection responsibilities and procedures in the connected Member State). However, this may require a change in the grid connection regime of the hosting Member State. In a shallow grid-connection regime where the connection is largely built by the TSO, this would also imply the grid connection costs would initially occur in the connected country.
- **Form of support:** The form of support could remain the same as in the hosting Member State, in line with the support scheme philosophy established in that Member State.[314] However, the form of support may impact the dispatch of the OWP, which in turn directly and only impacts the Member State to which the OWP is connected. Thus, the connected Member State may have a preference to implement the form of support used for its national OWPs. In addition, if a floating premium or CfD is applied, the reference price of the host Member State could be used. However, as the OWP feeds into the connected Member State, the suitable reference would be that of the connected Member State.
- **Tender design:** The tender design may be implemented as in the host Member State, which is unlikely to create adverse impacts on tender design in the connected Member State.

While the site selection is likely to be driven by the hosting Member State and the tender design of the host may be used, the grid connection regime and the form of support (including reference price) should be aligned with the connected Member State.

Option 2: Embed the OWP in the support scheme of the connected country

The more suitable solution appears to be using the support scheme of the connected Member State. In this case, the site selection would still be driven by the hosting Member State but the grid connection, the form of support (including reference price), and the tender design would be embedded into the support scheme of the connected Member State. The cooperation agreement would have to define that the connected Member State has the authority to select a project and apply its form of support. Table 3-14 details the initial distribution of costs and benefits:

Table 3-14. Impact on relevant parties for the CBCA in case 2.

Cost and benefit indicators	Impacted parties	Host country	Connected country
CAPEX and OPEX of infrastructure element	TSO	0	(-)
Congestion rents (part of SEW in CBA)	TSO	0	0
Additional redispatch (redispatch reserves in CBA)	TSO	0	(-)
System flexibility (part of security of supply in CBA)	TSO	0	(-)
Investment deferral – infrastructure	TSO	0	(-)
CAPEX and OPEX for generation asset	Generation project developer	(-)	(0)

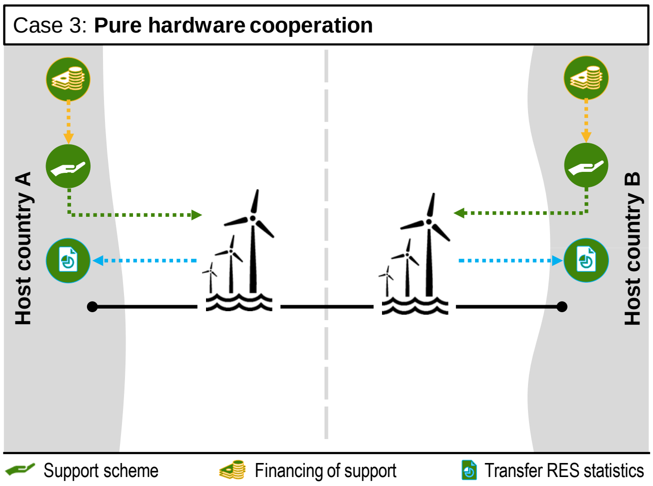
[314] Note that most support schemes require the OWP to have a direct connection to the supporting country to receive support payments (i.e. only receive support if the renewable energy is physically fed into the electricity system of that Member State). Such provisions would have to be changed in this option.

Market revenues	Generation project developer/operator	0	(+)
Support scheme payments	Member States (their levy/taxpayers) and project developer	0	(-)
RES target statistics (part of RES integration in CBA)	Member State	(+)	0
Effects on wholesale market price (part of SEW in CBA)	Member State (their consumers)	0	(-)
(Non-)CO_2 emissions	Member State	(?)	0
Use of RES potential (part of investment deferral in CBA)	Member State	(-)	0

The key elements the host Member State would focus on for the CBCA are the RES statistics from the OWP, potentially emission impacts (or landscape impacts), and the use of its RES potential for a plant feeding into the connected Member State. In the case of a single OWP and thus limited system effects, the connected Member State would focus on the infrastructure costs (i.e. connection to shore), and the support costs.

A pragmatic approach to the CBCA may mean that the host Member State transfers the RES statistics to the connected Member State and keeps the RES share it requires to offset the impacts of giving away the respective RES potential (e.g. 80% transfer, keeping 20% for the use of its valuable sites). If the host Member State is interested in keeping a higher share of RES statistics for target achievement purposes, the two Member State may agree an additional statistical transfer related to an explicit transfer price. Price considerations would then be based on the willingness to sell and to buy of the involved Member States.

3.2.4.3 Case 3: Hybrid - hardware-only



In this setup, the project is a hybrid, it includes an interconnector functionality. One OWP is in each of two EEZs and connected to their respective shores while being connected to each other. Each Member State uses its respective support scheme and keeps the RES statistics produced from the OWPs in their EEZ.

Examples of this setup could include projects like WindConnector, Nautilus, Kriegers Flak, and the Cobra Cable project.

Cross-border cost allocation

The CBCA will be limited to the infrastructure aspects and system impacts related to the TSOs and will result in an inter-TSO compensation, according to processes established in the TEN-E regulation. If one TSO (Host country A) pre-finances the entire interconnection between the two wind farms, and host country A (e.g. DK) has structurally lower wholesale market prices compared to host country B (e.g. Germany) (and thus electricity is usually traded from A to B), the impacts Table 3-15 may occur.

Table 3-15. Impact on relevant parties for the CBCA in case 3 when one TSO pre-finances.

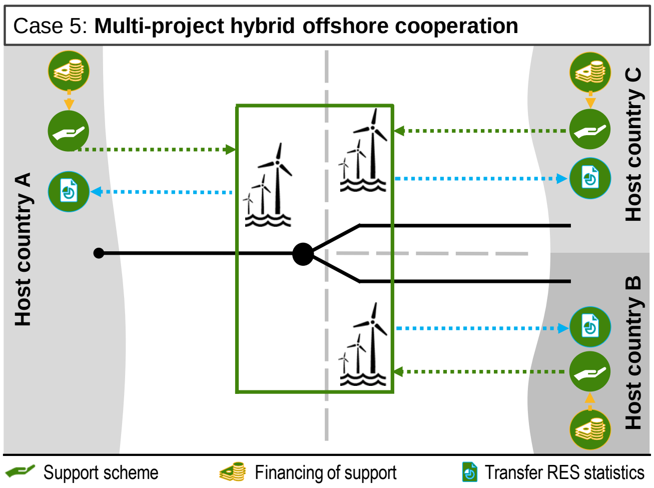
Cost and benefit indicators	Impacted parties	Host country A	Host country B
CAPEX and OPEX of infrastructure element	TSO	(-)	0
Congestion rents (part of SEW in CBA)	TSO	(+) 50%	(+) 50%
Additional redispatch (redispatch reserves in CBA)	TSO	(+) (decrease in redispatch)	(-) (increase in redispatch)
System flexibility (part of security of supply in CBA)	TSO	(+)	(+)
Investment deferral – infrastructure	TSO	(+)	(-)
CAPEX and OPEX for generation asset	Generation project developer	0	0
Market revenues	Generation project developer/operator	0	0
Support scheme payments	Member States (their levy / tax payers) and project developer	0	0
RES target statistics (part of RES integration in CBA)	Member State	0	0
Effects on wholesale market price (part of SEW in CBA)	Member State (their consumers)	(-)	(+)
(Non-)CO_2 emissions	Member State	0	0
Use of RES potential (part of investment deferral in CBA)	Member State	0	0

Key impacts in this hypothetical case may include the initially paid CAPEX and expected OPEX for host country A, partially offset by the congestion rents. In addition, the TSO in Member State A may save costs for redispatch that it can avoid due to the interconnector. It may improve in terms of system flexibility and may be able to defer some internal grid investment. Wholesale market price effects would initially be non-significant and may be disregarded, specifically in view of the ambiguous effects of changing wholesale market prices on producers, consumers, and support payments. By contrast, Member State B may have to increase redispatch measures and may require additional internal grid investments to cope with new congestion in its electricity system due to the additional electricity import.

The initial investment cost may be split so the TSO of Member State B compensates the TSO of Member State A for less than 50% of the CAPEX and OPEX of the project (e.g. 30%). Alternatively, both TSOs may agree on splitting the CAPEX and OPEX 50/50 but transferring shares of their congestion rents according to the expected impacts. In this case, the TSO of Member State A may transfer a share of its congestion rents to the TSO in Member State B in order to compensate for the additional costs incurred (redispatch and investment). Such a compensation scheme between the TSOs would require changes in the TEN-E regulation and the EMR to allow for this form of compensation.

Case 4 is a variation of case 3.

3.2.4.4 Case 5: Multi-project hybrid - hardware and software



This setup would include an interconnector functionality and could include several OWP connected to the interconnector via a hub, one in each Member State (i.e. A, B, and C). The obvious example of this case could be the NSWPH, including the Netherlands, Germany, and Denmark (to limit the complexity of the case study).

Cooperation Software

The project could be conceptualised as a single cooperation approach (albeit with several generation assets connected). A new support scheme may be implemented (according to Article 13 of the RED II). This scheme would be funded by all three involved Member States. The support could be auctioned centrally by a single dedicated authority, via the EU RES financing mechanism or by a cooperation of the involved auction authorities (i.e. energy agencies or regulators).

Alternatively, the project may be split into separate cooperation projects, that is, a comprehensive infrastructure cooperation combined with single cooperation projects for each of the generation assets, which could each be handled separately and implemented individually. The advantage of such a fragmented approach is that each Member State may implement its own established auction and potentially support scheme. This may make the national implementation of this project easier compared to a comprehensive cooperation approach. However, such an approach would require close coordination of the national auctions. If a fragmented approach is taken, the cooperation would be reduced to the infrastructure elements of the projects (and to an inter-TSO cooperation) and benefits from cooperation on the generation assets may not be properly harvested.

For this case study, we assume the comprehensive cooperation approach, building on a joint support scheme. This ideally includes a centralised site selection process coordinated among the three Member States to allow for an optimal physical project setup. In addition, the grid connection regime would be aligned between the involved Member States for this specific project so to have comparable bids in the subsequent auction rounds and a coordinated grid connection process for the entire project. The project implies complex infrastructure solutions; a coordinated infrastructure planning between the involved TSOs would be required. This may imply a shallow grid connection regime to be applied for the project.

The form of support and the tender design ideally will be designed independently of the existing national schemes of each participating Member State to optimise the investment decisions and the operational performance of the project. The implementation of an OBZ has implications for the distribution of costs and benefits between TSOs and Member States and between the energy producers and the TSOs (as in such a setup the TSOs congestion rents increase and the electricity producer’s revenues decrease). For practical and legal reasons, we do not assume a redistribution of congestion rents from the TSOs to the electricity producers. The tender design would likely include site-specific and single item auctions, one for each generation asset. In any case, the project would not be tendered in its entirety (i.e. infrastructure and generation asset); only the generation assets, in line with state aid rules, would be allocated in a competitive process.

Table 3-16 includes the hypothetical impacts for the involved parties.

Table 3-16. Impact on relevant parties for the CBCA in case 5.

Cost and benefit indicators	Impacted parties	Host country A (NL)	Host country B (DEU)	Host country C (DK)
CAPEX and OPEX of infrastructure element	TSO	(-) (incl. the hub)	(-) (connection to shore)	(-) (connection to shore)
Congestion rents (part of SEW in CBA)	TSO	(+)	(+)	(+)
Additional redispatch (redispatch reserves in CBA)	TSO	(-)	(-)	(+)
System flexibility (part of security of supply in CBA)	TSO	(+)	(+)	(+)
Investment deferral – infrastructure	TSO	(-)	(-)	(+)
CAPEX and OPEX for generation asset	Generation project developer	(-)	(-)	(-)
Market revenues	Generation project developer/operator	(+)	(+)	(+)
Support scheme payments	Member States (their levy/taxpayers) and project developer	(-)	(-)	(-)
RES target statistics (part of RES integration in CBA)	Member State	(+)	(+)	(+)
Effects on wholesale market price (part of SEW in CBA)	Member State (their consumers)	(+)	(+)	(-)
Non-CO_2 emissions	Member State	(-)	(-)	(-)
Use of RES potential (part of investment deferral in CBA)	Member State	(-)	(+)	(+)

The main cost benefit impacts would include the hub and the connections to shore, while the hub (if located in Member State A) would be pre-financed by the TSO of Member State A. The congestion rents would increase for the TSOs, especially in the OBZ setup and offset the CAPEX and OPEX of the infrastructure investment. We assume additional redispatch reserves are necessary in Member State A and Member State B as lower market prices in Member State C imply exports to Member State A and Member State B, which are largely based on non-dispatchable renewables. This aspect would also potentially lead to additional grid reinforcement being necessary in Member State A and Member State B as a result of the project. System flexibility may increase for all involved TSOs, due to the additional interconnector capacity.

Member States make the support schemes payments according to the predefined share, correlating with the target statistics they envisage to receive from the project. Effects on the wholesale market may imply decreasing prices in Member State A and Member State B and increasing prices in Member State C due to the additional interconnector capacity. This impact is ambivalent as it increases consumer surplus in Member State A and Member State B (decreasing in Member State C), but decreases producer surplus in Member State A and Member State B (increasing in Member State C) which partly have to be offset by existing generation capacities through the respective (floating premium) support schemes. The use of RES potential would be equal for the generation assets if the same capacities are built in each of the three Member States. This may change if significantly more capacities would be built in one Member State compared to the others, impacting the redistribution of the RES statistics.

The actual redistribution required in this case is too complex to be discussed in full in this case study. However, the following elements may form part of the redistribution:

- The hub should potentially be paid for equally by all three TSOs. The TSOs in Member State A and Member State B would have to be compensated by the TSO in Member State C for additional grid reinforcement in their onshore bidding zone.

- Congestion rents may then be split according to the expected share of the expected net benefits per involved TSO (reflecting additional redispatch for each bidding zone).

- Member States may seek to base their share of support scheme payments on the exact output of the specific plants located in their territory, but this would complicate determining the shares needed for the joint support scheme. A flat-rate approach (i.e. pro-rata share) for the entirety of RES production appears advisable in this context and also reflects on the comprehensive scope of the project.

- The flat-rate approach may be adjusted by various factors:

  The offshore bidding zone requires more support payments for Denmark and the Netherlands compared to an OBZ (and a radially connected OWP). This effect almost does not occur for Member State C as the onshore price level may be more similar to the one in the OBZ. Although the support costs may be paid for equally by all three Member States (33.3% each), Member State A and Member State B may receive a higher share (e.g. 40% and 40% vs. 20% for Member State C).

  The hypothetical use of more offshore RES potential in Member State A compared to Member State B and C would justify a further increase of the RES share for Member State A (e.g. 45% for Member State A, 35% for Member State B, and 20% for Member State C).

Such a high level approach would imply actual compensation payments between the TSOs and full compensation by adjusting the RES statistics between the Member States. The suggested shifts may materialise in different ways, depending on which impacts are expected based on proper quantification and monetisation of the key aspects. In addition, they would substantially change depending on the actual generation capacities envisaged in each territory.

The resulting share of RES statistics may be adjusted further in case one Member State is in more need of RES statistics than another. In this case, additional compensation payments (including an explicit transfer price per kilowatt-hour) may be agreed for this adjustment, similar to transfer prices in pure statistical transfers.

The CBCA approach for a complex (and flexible) concept like the NSWPH requires a much deeper analysis than can be provided in this context but showing the general structure of potential key impacts and compensation approaches helps to identify follow-up questions. A separate in-depth case study on the cooperation software and possible CBCA approaches for a hub-based concept, such as the NSWPH, is advisable.

3.3 Recommendations on the use of the CEF and the Renewables Financing Mechanism for joint (hybrid) OWP

Especially hybrid configurations that entail interconnection and generation asset components may not be expected to rely on one single point of access to EU funding. Rather, these hybrid projects might have to combine funding from different sources. These sources may include the planned funding line for renewables cross border projects (c-b RES) and the more established CEF Energy/PCIs funding line targeting energy infrastructure—depending on whether financial assistance relates to generation and/or grid connection or interconnection infrastructure. Moreover, funding may be combined with resources from the Recovery and Resilience Facility (in which case the project in question would have to be enshrined into the recovery plan of the Member State. Hybrid projects may participate in auctions under the Renewables Financing Mechanism foreseen under Article 33 of the Governance Regulation (Regulation (EU) 2018/1999) to receive support payments.

This section provides recommendations on the possible use of the revised CEF, including the planned c-b RES funding line as well the Renewables Financing Mechanism in the context of hybrid assets. Section 3.3.1 provides recommendations for the use of CEF Energy/PCIs and the c-b RES funding line for hybrid offshore projects. Section 3.3.2 discusses scenarios under which hybrid OWP may participate in auctions organised by the Financing Mechanism.

3.3.1 Recommendations for the use of the CEF Energy/PCIs and c-b RES support windows in the case of (hybrid) OWP

This section describes the CEF, including the new window for c-b RES projects. It also develops recommendations for a coordinated approach to the use of the CEF Energy/PCIs and c-b RES support windows in the case of (hybrid) OWP.

Connecting Europe Facility (CEF), including new window for c-b RES projects

Since its introduction in January 2014, CEF has been the key EU funding instrument to support the development of interconnected trans-European networks in the sectors of energy, transport, and telecommunications (i.e. CEF Energy/PCIs, CEF Transport, CEF Telecom). In addition to grants, the CEF offers financial support to projects through financial instruments such as guarantees and project bonds. INEA is responsible for implementing CEF, including the organisation of selection procedures for eligible projects and following up on technical and financial implementation of funded actions.

CEF Energy/PCIs is the instrument's central funding line to support energy infrastructure investments, i.e. funding for works and studies. To be eligible for funding under CEF Energy/PCIs, actions intending to receive support from CEF Energy/PCIs need to contribute towards the realisation of one or several PCI, which are predefined trans-European or cross-border energy infrastructure projects in eight priority corridors (of which four are in the electricity sector) and in two thematic areas, including on smart grids. These priority corridors are thematic areas defined in the TEN-E strategy. One of these priority corridors is the Northern Seas Offshore Grid corridor, in which CEF funding totalling €112.2 million has been awarded to 19 actions until the end of 2018.[315]

The list of PCIs is adopted by the European Commission and updated every 2 years. On 31 October 2019, the Commission adopted its fourth list of PCIs containing 151 projects. In the electricity sector, the projects involve electricity transmission lines and interconnectors, electricity storage projects, and smart grid projects. Actions contributing to these PCIs are funded as a result of regular calls for proposals (so far, eight calls for proposals have taken place) and are managed by INEA. They benefit from accelerated licencing procedures, improved regulatory conditions, and access to financial support totalling €5.85 billion from CEF between 2014 and 2020.

The Commission's proposal for the new CEF includes a category for cross-border projects in the field of renewable energy (c-b RES projects). On 8 March 2019, the European Parliament and the Council reached a common understanding on the proposal for a revised CEF Regulation for 2021-2027. According to it, 15% of CEF Energy/PCIs (i.e. €875 million, subject to final MFF decision) are made available for c-b RES projects. If that amount is reached, the Commission may increase it to 20% of the CEF Energy/PCIs budget. The funding line shall also provide for possible blending with other EU programs, including the proposed new InvestEU Fund.

In principle, the funding line shall provide support for:

- Grants for pre-feasibility studies for EU Member States and project promoters to assess and develop jointly beneficial cooperation mechanisms.

[315] EC, 2019. Connecting Europe Facility. ENERGY. Supported Actions – May 2019. https://ec.europa.eu/inea/sites/inea/files/cefpub/cef_energy_brochure_2019-web.pdf

- Grants for technical studies, i.e. more detailed studies undertaken only once a cooperation or project was granted the status of a c-b RES project.

- Grants for works for a limited number of c-b RES projects.

A delegated act with further details on the selection criteria and process is to be presented by the European Commission shortly after the MFF is adopted. Moreover, the Commission needs to develop and publish the methodologies to assess the costs and benefits of any proposed cooperation/project and the contribution to the general objectives as specified in Annex Part IV of the proposed CEF regulation.

The proposed selection procedure (see Study ENER/C1/2018-554 for more details) includes various application stages that projects have to pass from pre-feasibility studies to receiving grants for works (see Figure 3-9).

Figure 3-9. Overview of application stages for c-b RES projects *(source: Guidehouse)*

The application stages and its related benefits for project promoters include:

- **Pre-Status:** Application for and awarding of early feasibility study. The CEF regulation includes the possibility of projects/applicants to receive funding for studies at an early stage of a project. Such studies may help to further develop and sharpen the project idea and to create momentum among the required stakeholders for a c-b RES project. The amount to support such early studies will likely be limited (e.g. max €150,000) and will be smaller than amounts for detailed technical studies or grants for works.

- **Application and award of status as c-b RES project:** The status as a c-b RES project under the CEF regulation would make projects eligible to receive funding for detailed technical studies (e.g. feasibility studies for project promoters and other eligible entities to prepare concrete projects emerging from cross-border cooperation). In addition, projects with this status are generally eligible to receive grants for work, as they provide high EU added value and significant overall cost savings.

- **Detailed technical studies after receiving c-b RES project status:** The status as a c-b RES project provides eligibility for support for detailed technical studies.

- **Application for and awarding of grants for works:** This stage includes the main objective of applicants, the awarding of grants for works that otherwise (even when considering payments from national support schemes) would not materialise because they would not be economically viable.

The early feasibility studies (pre-status) can be skipped, and project promoters may apply for several stages at the same time in case they want to quickly advance in the process. For instance, they may apply for the c-b RES project status and at the same time for the grants for technical studies or even for grants for works.

The common understanding on the proposal for a revised CEF Regulation for 2021-2027 includes several indications on what project types may be eligible for funding as a c-b RES project. Eligible technologies are in principle those defined as renewable energy generation technologies in the REDII (Article 2), i.e. “wind, solar (solar thermal and solar PV) and geothermal energy, ambient energy, tide, wave and other ocean energy, hydropower, biomass, landfill gas, sewage treatment plant gas, and biogas.” Renewables generation may be related to the electricity, heating and cooling, and transport sectors, as “eligible action is not limited to the electricity sector and can cover other energy carriers and potential sector coupling for example with heating and cooling, power to gas, storage and transport.”

Eligible entities are Member States and legal entities established in a Member State including JVs; legal entities established in a third country associated to the programme or overseas countries and territories; legal entities created under EU law and international organisations (where provided for in the work programmes). There is no limitation on project size. In addition, either individual projects may apply or multiple projects (e.g. a joint support scheme implemented by more than one Member State), i.e. Member States can also apply for grants to support joint support schemes instead of specific physical assets. In sum, the range of potentially eligible projects is large, resulting from the idea to provide as much flexibility as possible to allow for innovative approaches providing the largest added value.

How can support from CEF Energy/PCIs and CEF c-b RES be used for (hybrid) OWP?

The main feature determining if hybrid offshore assets may receive support from either of the funding lines under CEF is whether the requested financial assistance may be used for the generation or the interconnector component of the hybrid project. We describe in what way hybrid assets can benefit from support under CEF funding lines individually before providing high level recommendations on a coordinated approach to their use.

Use of financial assistance from CEF Energy/PCIs

CEF Energy/PCIs focusses on energy infrastructure investments that contribute towards the realisation of trans-European PCIs in certain priority corridors. This implies that support towards the generation component of the hybrid asset will generally not be possible from CEF Energy/PCIs, but rather be relevant for those hybrid offshore assets involving an interconnector. As a result, CEF Energy/PCIs financial assistance would mostly be relevant for hybrid offshore configurations that include an interconnector functionality, i.e. Case 3 – “Pure hardware cooperation,” Case 4 – “Simple hybrid offshore cooperation” and Case 5 – “Multi-project hybrid offshore cooperation.” Since Case 3 constitutes a pure hardware cooperation between Member States related to the joint construction of an interconnector, funding from CEF Energy/PCIs would likely not have to be combined with other forms of support (e.g. from CEF c-b RES funding line).

Before being able to apply for financial assistance under CEF, project promoters (e.g. Member States, TSOs) need to ensure that the interconnector for which they seek support is part of the Union PCI list (in particular the Northern Seas Offshore Grid priority corridor). As outlined above, the list of the PCIs is adopted by the European Commission and updated every two years. These timeframes need to be considered as part of the overall application process to ensure eligibility for funding. Once the status as a PCI (or as a part thereof) has been granted, project promoters (i.e. Member States, TSOs) submit a project proposal concerning the relevant interconnector component of their hybrid project under a call for proposals organised by INEA. If successful in the (cost-based) selection procedure, they receive investment grants for the implementation of the interconnector (up to a co-funding rate of between 50% and 75%). Since funding only relates to the interconnector, financial assistance for the generation assets forming part of the overall hybrid project need to be procured through other means (e.g. CEF c-b RES, renewables financing mechanism, national support schemes). In the absence of a coordinated approach between different funding sources, collecting the required financial assistance from different sources needs to be adequately sequenced to ensure the timely realisation of the overall project.[316]

Use of financial assistance from CEF c-b RES

The common understanding on the proposal for a revised CEF Regulation for 2021-2027 states that eligible technologies are in principle those defined as renewable energy generation technologies in the REDII (article 2), including offshore wind as well as connection to the grid and storage and conversion facilities. As a result, support from the CEF c-b RES window may be used for OWP, that may be part of hybrid project configurations. In principle, support from CEF c-b RES may relate to the generation component of any project setup, as section 3.1.3 describes, that can be embedded into a cooperation agreement between Member States as defined in RED II relating to a sharing of costs and benefits on the level of the generation asset (i.e. Cases 1, 2, 4, and 5). For example, Case 1 – "Pure RES target achievement cooperation," while not involving a physical interconnection between countries, would be eligible on the basis that it is implemented as a joint project as set out in Article 9 of the RED II. In addition, CEF grants to co-fund joint support schemes instead of specific physical assets are generally possible.

Using CEF c-b RES as the single source of financial assistance is the most straightforward way through which OWP can make use of the funds (i.e. not making additional use of a potential national or joint support scheme). Any adverse interactions between different support schemes (e.g. the risk of overfunding) are naturally not applicable in this case. Before applying for grants, project promoters need to ensure that the OWP has received the status as a c-b RES project. Once projects receive this status, project promoters may submit a project proposal (including a CBA) to receive financial assistance to implement the generation asset(s) under a relevant call for proposals organised by INEA. If successful in the (cost-based) selection procedure, they receive a grant (up to 50% of eligible costs) for the implementation of their OWP. Besides grants for works, project promoters may also apply for grants for technical studies or preparatory studies to further develop a joint project idea (e.g. for a hybrid offshore project). Since funding only relates to the generation component, financial assistance for a potential interconnector forming part of the overall hybrid project (Case 4 and 5) needs to be procured through other means (e.g. CEF Energy/PCI). In the absence of a coordinated approach between different funding sources, collecting the required financial assistance from different sources needs to be adequately sequenced to ensure the timely realisation of the overall project.

Support may be combined from national/joint support schemes with additional financial assistance from CEF c-b RES (e.g. to cover additional costs related to OBZ or strategic importance at EU level). To avoid challenges in the combination of funds by individual projects, CEF financial assistance may target (joint) support schemes directly. Member States contributing to a joint support scheme for (hybrid) OWP (e.g. Case 5) rather than individual project developers apply for CEF financial assistance for a (hybrid) project idea. CEF financial assistance (if granted) would then be made available to allocate grants to any project developer that is awarded in the respective site-specific tenders under the support scheme. As a result, all participants in the auction occurring under the joint support scheme compete on a level playing field—all bidders can consider the CEF grant in their bid, which they would receive upon being awarded in the auction. This reduces the risks of market distortions compared to a situation where project developers individually combine support scheme revenues with CEF grants.

Under this option, additional CEF grants may be applicable to cover the gap between the expected cost of the joint support scheme and the willingness-to-pay from the Member States jointly financing the support scheme. In this context, additional funds from the planned Recovery and Resilience Facility proposed as part of the NextGenerationEU recovery instrument may be used by Member States to (partly) finance their national support schemes However, the details of such opportunities for EU co-financing through the Recovery and Resilience Facility are yet to be determined. In principle,

[316] One currently discussed option is the inclusion of a generation and storage element in the revised TEN-E regulation besides transmission/interconnector infrastructure. This would for example allow projects including both generation/storage components and interconnectors to receive funding under CEF Energy/PCIs. In this case the combination of support for the implementation of hybrid OWP from different funding lines may no longer be necessary.

the aim of a joint support scheme is to fully cover all arising support costs—there would be no gap to cover and hence no CEF grant needed. Consequently, joint support schemes seeking CEF grants for work would have to demonstrate that the need for CEF co-funding is related to additional costs and that these costs are justified. Schemes would need to demonstrate strategic importance at the EU level or justify additional costs that should be borne at the EU level rather than by a national/joint support scheme (e.g. supporting value chains, industrial leadership). Such justifications may exist in hybrid offshore projects and a potential combination of support may be warranted. For example, if assessed against the counterfactual of radially connected OWP, EU funds may be relevant on the basis that hybrid OWP can result in additional support costs (because of technical complexities and coordination requirements or because of structurally lower revenues resulting from OWP location in OBZ). In particular, additional EU funds could be useful to partially compensate higher support costs resulting from the structurally lower revenues that OWP located in an OBZ face (see section 3.1.4.3) and so increase the attractiveness of establishing OBZ more generally.

Theoretically, individual OWP may combine support from national/joint support schemes with additional financial assistance from CEF c-b RES. Under this option, OWP project promoters individually participate in national/joint support schemes first and then submit their CEF application once they have confirmation of this grant (if any). Since the CEF grant is designed to close the funding gap that remains after all revenues have been considered, including those from other support schemes, the CEF grant can be calculated considering the previously allocated support to avoid overfunding.

Compared to a coordinated approach between the different support schemes, transaction costs for bidders are high since they need to individually acquire support from two funding sources. This approach also entails major adverse effects in that it creates market distortions, inhibits the binding character of bids submitted in national/joint auctions, and increases the risk of the winner’s curse. More specifically, project developers participating in national/joint auctions would consider a possible CEF grant in the calculation of the bid to gain a competitive advantage over other bidders (if competition is sufficient). This would generally result in lower bids for those bidders that expect receiving a CEF grant at later stages compared to bidders that are not able or willing to secure CEF funding, which may result in market distortions (i.e. projects receiving the highest overall support level are most competitive). This increases the winner’s curse since bidders can bid lower bid prices in expectation of receiving CEF financial assistance than without such grants. However, these bids would only be viable in case of a successful allocation of grants from CEF. If projects fail to secure grants after having participated in auctions, their previously submitted bid prices would be too low to ensure the project’s commercial viability. The project could not be realised as a result. Hence, bids submitted under a national/joint support scheme would result in a lower realisation rate, which is one of the key conditions for successful auctions. A non-coordinated combination of CEF grants and support allocated through national/joint support schemes by individual project promoters is not advisable.

Coordinated approach to the use of the CEF Energy/PCIs and c-b RES for hybrid projects

Hybrid OWP may have to rely on different sources of EU funding given their characteristic combination of transmission and generation assets. This may increase transaction costs for project promoters of hybrid assets intending to apply for EU funding and might even impose prohibitive barriers for the development of such projects if funding is unavailable or cannot be procured in a timely and coordinated manner for both its transmission and generation component.

In principle, CEF offers financial assistance to the two major components of hybrid projects—the generation asset and the interconnector—but applications usually need to be submitted under different calls for proposals relating to the CEF Energy/PCIs and c-b RES funding line. To reduce transaction costs for applicants and increase the effectiveness of EU support, establishing a sufficiently coordinated process for the use of both CEF funding lines will be crucial to contribute to a better integrated EU support framework for hybrid offshore projects. We describe and discuss main approaches for an increased coordination between the two funding lines below.

Structural mixing of CEF Energy/PCIs and c-b RES funding lines

The rationale of this option is to create a one stop shop for project promoters by consolidating and temporally aligning the application and selection process, budgets, payment streams, and reporting and monitoring processes of both funding lines into one procedure. This would require a close coordination of PCI processes and the process to receive the status as c-b RES project to allow for an adequate sequencing of applications and avoid project development delays. Alternatively, the process to receive both statuses may be merged into one procedure for hybrid projects; such projects would only be required to receive one status. In this context, the inclusion of a dedicated category for hybrid OWP as part of CEF Energy/PCIs is one option, and it would require a respective amendment of the revised TEN-E regulation. This would allow such projects to receive funding from CEF Energy/PCIs alone rather than having to combine funding from both CEF Energy support windows. In this case, a hybrid OWP would only have to apply for the PCI status without having to obtain the additional status as a c-b RES project.

Another option to implement a structural mixing of both funding lines would be the organisation of synergy calls that select projects in line with both funding objectives: a common work programme and unified award criteria. Calls for proposals and their priorities could be tailored to allow for the selection of renewable energy projects that entail both infrastructure and generation assets or even include a dedicated reference for hybrid offshore projects. However, the revised CEF in its current form only allows for synergy calls between different sectors, while a common call between the two CEF Energy windows is not covered directly.

Such far-reaching coordination between the funding lines would reduce transaction costs for project promoters significantly and could potentially support a more effective combination of funds to the benefit of hybrid projects. At the same time, structural mixing between both funding lines may require specific legislative provisions to support deep coordination between the two funding lines (e.g. the inclusion of a new category for hybrid projects in CEF Energy/PCIs). Given the recent agreement on the common understanding of the new CEF regulation, a complete alignment of both funding lines may be unrealistic in the short- to mid-term. The revised CEF regulation strongly emphasises funding synergy actions that contribute to more than one objective (see Article 10). Moreover, the links between CEF Energy/PCIs and CEF c-b RES funding lines are generally stronger compared to the remaining CEF funding lines, including budgetary interdependencies (e.g. available budget for c-b RES projects expressed as share of overall CEF Energy budget).

Coordination of work programmes and calls for proposals

This option follows the principle of aligning funds as much as possible without structurally mixing them—individual application and selection process remain in place but are coordinated to a significant degree. Activities coordinated between the funding lines may include the schedule and timeline of calls for proposals and work programs, eligibility and selection criteria, and application technicalities. Since each support window would still be responsible for its part of the support scheme (i.e. the infrastructure or the generation asset), contracts with awarded projects and disbursement of support would be handled individually by each funding line for the respective component of the overall project to be funded.

In the context of hybrid OWP, separate (but coordinated) application, selection, and grant disbursement procedures may provide practical and legal advantages compared to fully unified processes. First, relevant project promoters (applicants), will differ for the infrastructure component (i.e. Member States and TSOs in case of a TSO-led process) and the generation asset (i.e. usually private project developers) requiring substantial coordination between these players. Second, the structural combination of a TSO with a project developer as part of a fixed consortium would likely pose challenges to unbundling rules. By contrast, pure coordination between the funding lines would allow TSOs to apply for CEF Energy/PCI grants, while grid access would be open for any project developer that applies for grants under CEF c-b RES. Moreover, this approach would reduce the transaction costs for project promoters and has the potential to noticeably increase the effectiveness of EU support for hybrid projects, even though the effect may be weaker than in the previous option due to the less pronounced consolidation of processes. At the same time, this approach is not associated with fundamental legal or political requirements. Coordination does not need to be fully in place but can be strengthened gradually over time. INEA jointly manages all CEF funding lines, which may facilitate increased coordination between both funding lines. However, it is challenging to aim for fully integrated cost-benefit allocation decisions, as the revenue and support streams would initially be separate in this approach.

Coordination between the two funding lines may also be implemented via different funding priorities

One option would be that the c-b RES funding line focusses on funding for the preparation of preliminary and technical studies of hybrid OWP, while CEF Energy/PCIs focusses on providing support for the implementation of such projects. This would require the inclusion of a new category for hybrid projects under the revised TEN-E regulation. Since generation and transmission components of the hybrid project would be eligible for support under CEF Energy/PCIs, the construction of hybrid OWP could rely on support from CEF Energy/PCIs alone rather than having to combine support from both CEF Energy support windows. This would significantly decrease transaction costs for project promoters. Such an approach may be beneficial given the limited resources available to the c-b RES funding line (i.e. €875 million, subject to final MFF decision) and the limited capacity additions that could be supported under this window. Assuming hypothetical support needs of €180 per kW,[317] capacity additions of up to 4.3 GW could receive support under the c-b RES funding line. Hence, c-b RES funding would have insignificant contributions to the offshore wind deployment targets in NSEC countries (excluding the UK) of roughly 40 GW until 2030 (Figure 2-1). Moreover, this assumes that the available funding in the c-b RES support window would be fully allocated to OWP, which is unlikely since other RES technologies are eligible to receive support under this funding line. Against this background, bundling these limited funds to support preliminary and technical studies may be more effective than using them more broadly to also allocate grants to a limited number of (hybrid) OWP. At the same time, the allocated funding amounts as specified in the upcoming MFF only refer to 2021 until 2027. Hence, additional EU funds that could contribute to offshore wind targets may become available in the second half of this decade.

Provision of information on mixing options

This option constitutes a fallback option with minimal requirements regarding coordination or joint governance between the two funding lines. In this case, it would be ensured that project promoters contributing to hybrid projects and interested in EU support are informed about the availability of financial assistance from both funding lines (and potentially additional sources). The objective would be to advertise existing opportunities so that project promoters are fully aware of the advantages of combining EU support. Coordination of application process is not taking place under this option and combining different sources of EU funding would be at the full responsibility of the project promoter. There would be no alignment of schedules, eligibility criteria, or application technicalities.

This approach may lead to higher transaction costs for project developers intending to apply for support from different funding lines compared to the other options, potentially reducing the combined usage of funds and limiting support effectiveness in the case of hybrid assets. Choosing this option would not result in the integrated framework for the planning, tendering, financing, and cost-sharing of hybrid assets, which is the overarching goal of the assignment.

[317] This number is derived as follows: 10% of the rounded average investment costs of the Dutch OWP as identified by Lensink, Sander and Pisca, Iulia (2019): Costs of offshore wind energy 2018. https://www.pbl.nl/sites/default/files/downloads/pbl-2019-costs-of-offshore-wind-energy-2018_3623.pdf, p.6.

3.3.2 Recommendations for the use of the Financing Mechanism in the case of (hybrid) OWPs

This section describes the Renewables Financing Mechanism and elaborates on recommendations for its use in the case of hybrid OWPs.

Renewables Financing Mechanism (Article 33 Governance Regulation)

In its 2030 framework, the European Union has established a binding European Union-wide RES target of at least 32% in gross final energy consumption by 2030. This target is not the sum of national binding RES targets but is to be achieved through voluntary contributions of Member States, adding up to the EU 2030 target. One instrument to support and ensure the target achievement at European Union level is the "Union renewable energy financing mechanism" (the mechanism) as provided in Article 33 of the Governance Regulation. Article 33 also foresees an implementing act setting out the provisions necessary for the establishment and functioning of the mechanism. The following description is based on our recommendations as part of the assistance to the Commission in view of setting up the mechanism (Study ENER/C1/2018-568).

The basic functioning of the mechanism is relatively simple (see Figure 3-10). Member States may choose to make voluntary financial contributions to the mechanism, which are pooled as part of a dedicated budget line within the overall EU budget (potentially complemented by EU and private sector funds). The mechanism subsequently implements a competitive tender which determines support levels and allocates grants to RES projects in one or more host Member State(s) (or third countries), which choose to participate on a voluntary basis. The host Member State(s) transfer(s) the RES target statistics from these RES installations back to the mechanism, which then redistributes the RES statistics to the contributing Member States according to their share of financial contributions.

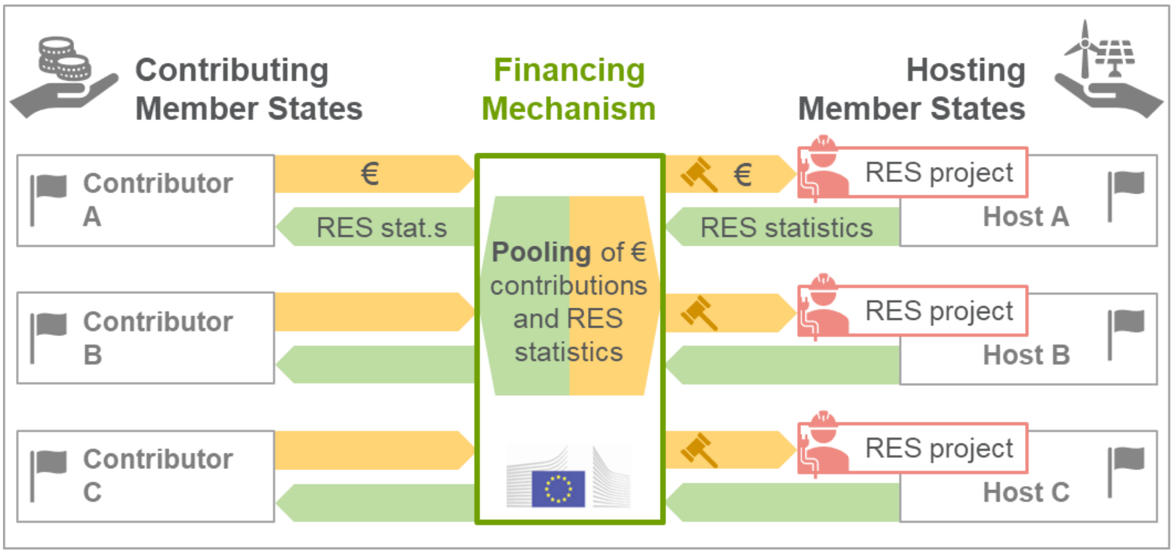


Figure 3-10. Basic structure of the Financing Mechanism *(source: Guidehouse)*

The mechanism may tender grants in three windows (see Figure 3-11). The technology-neutral window (aiming at a least-cost selection across technologies), the technology-specific window (aiming at a least-cost deployment of most acceptable technologies), and the project-specific window (focusing on strategic large-scale projects).

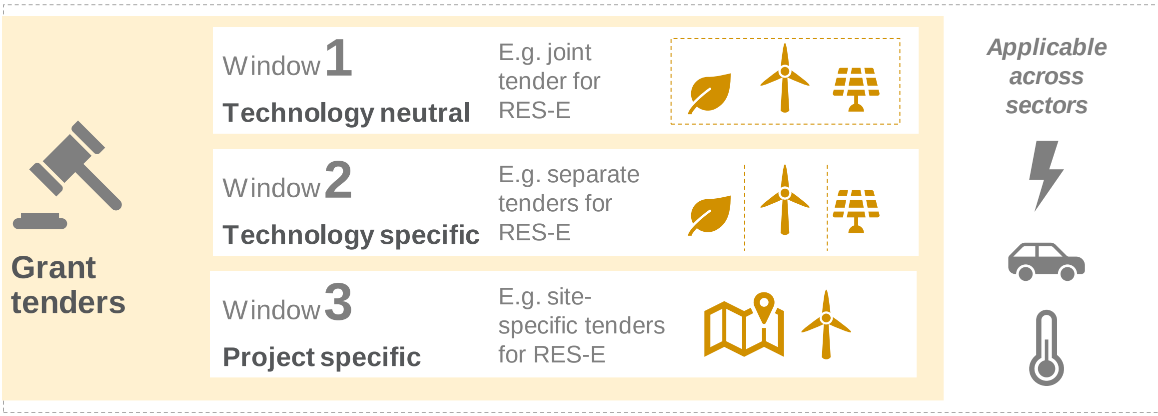


Figure 3-11. Overview of proposed windows under the Financing Mechanism
(source: Guidehouse)

The design of the support scheme for specific auction rounds organised under the Financing Mechanism ultimately depends on the objectives of the participating Member States and the Commission. The ease of implementation may be a relevant objective when organising tenders under the mechanism due to its overall administrative complexity and challenges pertaining to the need to swiftly implementing tender rounds across Member States. Hence, if the ease of implementation is a priority, technology-specific tenders for RES-E allocating investment support is the most viable option (combined with tendered item expressed in MW), despite there being less international experience with this type of support. Upfront investment support implies major administrative and practical advantages as it avoids the collection and payment of funds over longer periods of time and since it is applicable to all sectors and provides for effective market integration. By contrast, if the effective delivery of the gap-filling obligation under the Governance Regulation is the primary goal, the implementation of technology-specific tenders, preferably with well-known technologies is more recommendable (combined with tendered item expressed in MW and allocation of operating or investment support). Finally, if cost-effectiveness is key, the design package may combine the technology-neutral window with the tendered item expressed in megawatt and providing a fixed premium. Alternatively, technology-specific auctions focussing on a least-cost technology (combined with tendered item expressed in megawatt and investment support) may be used.

Allocation of costs and benefits: Statistical benefits based on energy generated by installations financed by the mechanism will be attributed relative to financial contributions by Member States. Hosting Member States forego part of their domestic RES potential and bear system integration costs for such installations. To account for this, a (flat-rate) splitting of statistical benefits between contributing and hosting Member States (e.g. 80/20) would be implemented, which may be renegotiated per tender round. System costs are not calculated and compensated on an individual cost-basis. Instead, the share of the statistical RES benefits that are retained by the host country (splitting rule) should be regarded as a compensation. In addition, host countries may internalise some of the system cost to RES projects through their regulatory framework (e.g. by applying deep connection charges).

Practical implementation and process: Procedures and the distribution of responsibilities need to be contractually determined between the European Commission and hosting countries to ensure that responsibilities and liabilities are defined between all parties and to ensure the mechanism's smooth function (e.g. related to the disbursement of support payments or monitoring of project implementation). In addition, minimum elements need to be contractually defined as part of the binding commitments with hosting (e.g. in terms of applicable restrictions) and contributing Member States (regarding their financial contribution and the allocation of statistical benefits). We proposed a procedure following several stages: the elaboration of work programmes, the tender preparation, (including an expression of interest phase and the binding commitments of participating host and contributing Member States), the tender implementation, and monitoring of project implementation, accounting of statistical benefits, and support payment disbursement.

How can support from the Financing Mechanism be used for (hybrid) OWP?

As expected in the Governance Regulation, the Renewables Financing Mechanism is an instrument that supports and ensures RES target achievement at European Union level. Member States contribute to the mechanism and expect to receive RES statistics in return. These statistical benefits are based on energy generated by installations financed by the mechanism and will be attributed relative to the financial contributions made by Member States (see Article 33 (5)). While support to installations can be provided in the form of either operational or investment aid, the mechanism focusses on supporting electricity generation expansion from RES, rather than infrastructure investments (the interconnector). Hybrid offshore assets may only receive support from the Financing Mechanism for the generation component of the project.

However, host countries may nonetheless internalise some of the system cost to RES projects through their regulatory framework. This particularly applies to grid extension and reinforcement costs that can be internalised through deep connection charges (i.e. renewable energy projects are charged the entire costs for grid connection, extension, and reinforcement related to the project). For hybrid offshore asset configurations, this means that connection to shore/interconnectors may be included in the support scheme design for specific auction rounds under the mechanism, depending on the host country's implemented connection cost regime (see section 3.1.4.2). In case a host country applies a deep connection cost regime, grid costs would be internalised in the bid price and then recovered via the support granted as part of the auction organised under the Financing Mechanism.

The mechanism includes various technology-windows: a technology-neutral window, a technology-specific window and a project-specific window. For hybrid OWP, auctions allocating investment or operating support are likely to take place under the mechanism's project-specific window following a central site-selection, given these projects' large scale and strategic relevance, and so the need to effectively coordinate planned OWP deployment. Due to the usually extensive infrastructure requirements for hybrid asset configurations, projects would likely be selected for a specific site and project configuration (site-specific, single-item auctions).

Although it is possible to use the mechanism to allocate support to hybrid OWP, this option is likely unrealistic. The mechanism achieves its full potential in the context of multiple contributing and hosting Member States, in that it entails the potential to reduce costs for renewable target achievement compared to a purely national deployment through competition between multiple sites in multiple hosting countries. By contrast, offshore wind sites are limited and would likely not be made available by Member States as a result of their strategic value to Member States intending to retain control over these sites. Especially if project setups are simple or do not entail multiple Member States (e.g. Case 4 – "Simple hybrid offshore cooperation"), in most cases, the use of the national host country support scheme or even a joint support scheme (in case of OWP located in more than one country) may also be easier to implement than the use of the EU-wide Financing Mechanism.

An opportunity to use the Financing Mechanism with hybrid OWP may arise in project setups, where several OWP in multiple Member States are connected to the interconnector via a hub (i.e. Case 5 – "Multi-project hybrid offshore cooperation"). Rather than implementing a joint support scheme, Member States may decide to let the mechanism tender support to available hybrid OWP. This may be relevant, for example, if contributing Member States cannot decide on a common support scheme design and intend to overcome this deadlock by adopting the mechanism's support scheme design. However, compared to the implementation of a joint tender, additional benefits are limited and mainly relate to the mechanism taking over the role of the responsible tendering authority. Rather than contributing to an established joint support scheme, Member States with OWP on their territory and potentially additional Member States intending to financially contribute to a hybrid project pay into the mechanism, which organises site-specific tenders for the relevant OWP to determine support levels and allocate grants to the successful bidders. The host Member States transfer the RES target statistics from these RES installations back to the mechanism which then redistributes the RES statistics to the contributing Member States according to their share of financial contributions. These steps otherwise would be taken over by cooperating national tendering authorities or a single dedicated authority in charge of auctioning support under the joint support scheme, depending on the specific agreement between Member States.

In multi-project hybrid offshore cooperation setups, the Financing Mechanism may become relevant, if additional EU funds are made available for the implementation of such a project. Such EU support may be justified to underline the strategic importance of hybrid offshore projects at European level, e.g. to support a European flagship project or to make OBZ more attractive by reducing national support costs (see section 3.1.1). In this context, the Financing Mechanism could provide an existing framework under which Member States and EU funds may be combined to promote the scale up of (hybrid) offshore wind capacities while increasing visibility on the importance all parties attach to these projects. At the same time, EU grants (e.g. from CEF) may contribute to joint support schemes to a similar effect without having to make use of the EU-wide Financing Mechanism.

If auctions under the Financing Mechanism are organised to allocate support to (hybrid) OWP, the tender design should be aligned with the considerations section 3.1.4.4 provides. The elaboration of an illustrative tender design will not be done separately.

3.3.3 Summary: Recommendations for the use of CEF and Financing Mechanism in the case of (hybrid) OWPs

In principle, CEF grants may be used for the infrastructure component (i.e. CEF Energy/PCIs funding line) and the generation component of hybrid OWP (CEF c-b RES funding line). For the generation component of hybrid OWPs, CEF c-b RES funding may be used as the single source of funding or CEF grants may be combined with support allocated through national/joint support schemes. The single use of CEF financial assistance is straightforward and avoids potential adverse effects (e.g. the risk of overfunding) that may arise if different funding sources at the national and EU levels are combined. If support from national/joint support schemes is combined with CEF financial assistance, this should follow a coordinated approach at the level of Member States rather than an uncoordinated combination of CEF grants and support allocated through national/joint support schemes by individual project promoters. In this context, additional funds from the planned Recovery and Resilience Facility may also be available for use by Member States to (partly) finance their national support schemes. However, the details of such opportunities for EU co-financing through the Recovery and Resilience Facility are yet to be determined.

To reduce applicants' transaction costs and increase effectiveness of EU support, the establishment of a sufficiently coordinated process for the use of both CEF funding lines should be established. The most advisable options are a structural mixing of both funding lines, e.g. as part of dedicated synergy calls targeting project setups that combine generation and interconnector components, or a coordination of the schedules and timelines of calls for proposals and work programs, including eligibility and selection criteria as well as application technicalities between funding lines. While providing a slightly lesser degree of efficiency gains compared to a structural mixing approach, the coordination of funding lines, whereby individual application and selection processes remain in place, avoids potential practical and legal problems in terms of unbundling rules between the main project promoters engaged in the transmission (i.e. mainly TSOs) and generation project components (i.e. private project developers).

Another option is the inclusion of a dedicated category for hybrid OWP as part of CEF Energy/PCIs, which would require a respective amendment of the revised TEN-E regulation. This would allow projects to receive funding from CEF Energy/PCIs alone rather than having to combine funding from both CEF Energy support windows. In this case, hybrid OWP would only have to apply for the PCI status without having to obtain the additional status as a c-b RES project, lowering transaction costs. Especially given the relative low funding volumes envisaged for the c-b RES funding line (i.e. €875 million, subject to the final MFF decision), coordinating funding priorities may increase overall support effectiveness. For example, the c-b RES funding line could focus on funding for the preparation of preliminary and technical studies of hybrid OWP, while CEF Energy/PCIs focusses on providing support for the actual implementation of such projects.

In principle, the use of the Financing Mechanism to allocate support to (hybrid) OWP is possible. However, the allocation of support to (hybrid) OWP through the mechanism may be unlikely, especially if project setups are simple or do not entail multiple Member States. In most cases, the use of a hosting country or joint support scheme will be more straightforward. Hence, multi-project hybrid offshore cooperation setups will likely remain the only conceivable use case. In particular, the allocation of support to (hybrid) OWPs could be relevant if additional EU funds are made available through the Financing Mechanism (e.g. to underline the strategic importance of "hybrid offshore flagship projects" or to increase the attractiveness of OBZ by reducing national support costs). In such scenarios, the mechanism may provide an existing framework under which Member States and EU funds can be combined to promote the deployment of offshore (hybrid) wind capacities. At the same time, combining EU funds with national funds may also be achieved through EU co-funding of national/joint support schemes (e.g. from CEF funds).

3.4 Integrated sequencing for the planning, tendering, and construction of hybrid assets

3.4.1 Introduction

This section presents illustrative timelines for each of the five identified hybrid configurations for offshore wind solutions and the transmission to the land-based high voltage transmission systems. Timelines are based on the processes for development, planning, permitting, and construction of offshore infrastructure and energy solutions. Elements include illustrative timelines and overall description of the following:

- **Maritime planning:** For wind generation assets and for transmission grid assets
- **Sizing of assets:** For wind generation assets and for transmission grid assets
- **Technical specification of assets:** For wind generation assets and for transmission grid assets
- **Request for funding support:** CEF and RES support for the wind generation part and CEF for the interconnector part
- **Modality for CBCA and CBCA decision**
- **Construction and commissioning activities:** For wind generation assets and for transmission grid assets

It is advisable to base any improvements on existing processes around planning, tendering and construction of cross-border hybrid offshore wind and transmission grid assets. This includes the strategy, overall planning, design, management, monitoring, verification, certification, and commissioning processes as well as integrated parts of the planning and installation/construction processes. This section presents guidelines that enable developers of offshore wind generation, transmission, and storage assets to cost-effectively expand with hybrid solutions that utilise the wind-energy potential of the North Sea It also details the need for expanding green and sustainable power solutions in the countries around the North Sea. The hybrid solutions combine existing offshore generation and transmission assets, which conventionally operate as separate entities, in new and more cost and energy efficient ways. These solutions also enable new projects to be linked into larger grid pools and to provide a platform for joint approach and coordination between countries.

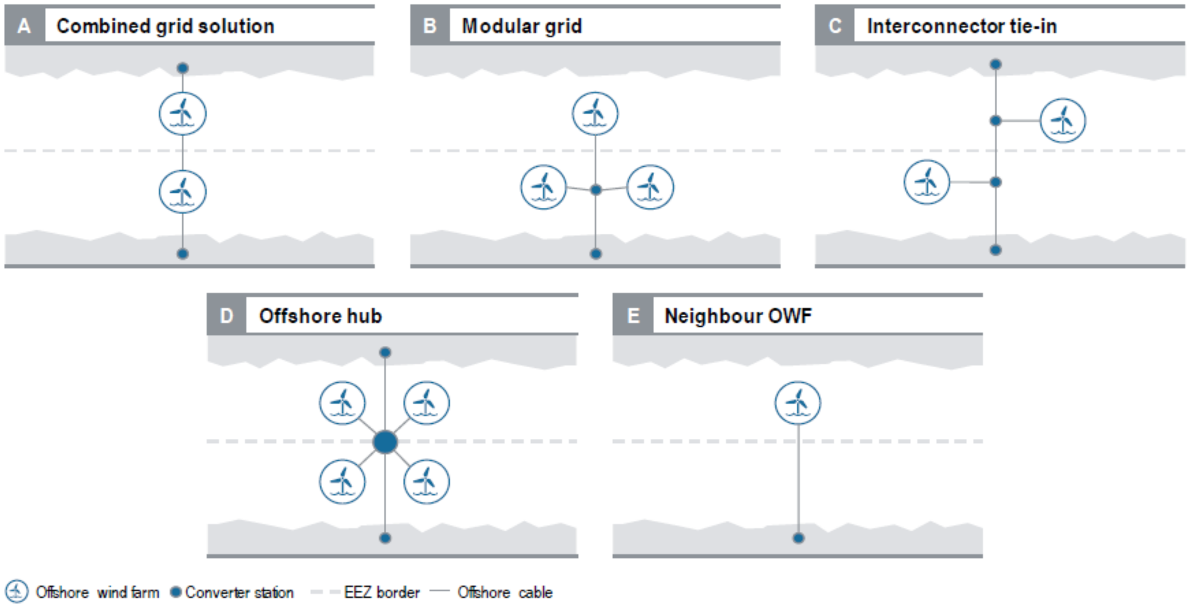


Figure 3-12. Five hybrid configurations as defined for the review.[318]

3.4.1.1 North Sea offshore wind farms

A large range of OWPs and transmission lines are already established in the North Sea and additional projects are in the process of preparation (planning, permitting, design, procurement) and construction. Figure 3-13 details the OWP areas. Numerous transmission systems and lines are established for the OWPs and other transmission lines for inter-country connections are established between the countries in the North Sea (Figure 3-15).

As the map shows, the areas designated for potential wind utilisation are significantly larger than the area covered by existing wind farms. The potential new wind farm areas are largely located far out in the North Sea from the existing wind farms. New cost-effective transmission solutions will support future development.

[318] Note that for task 2.4 the project setup oft he RB study are used. If deemed beneficial, they may be changed into the project setups defined for this report sin section 3.1.3.

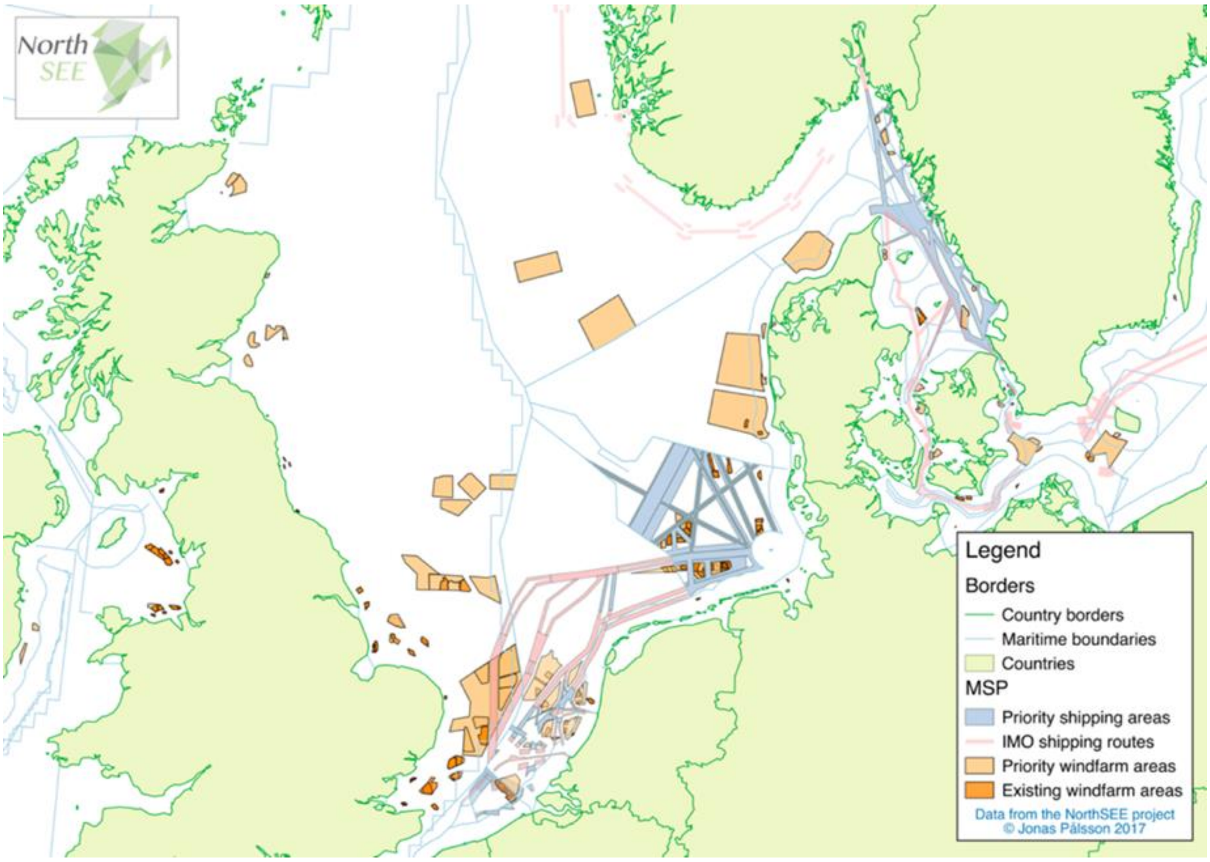


Figure 3-13. Existing and planned OWP areas in the North Sea. *(Source: NorthSEE)*

Figure 3-14 highlights the complexity of the OWPs in the German sector of the North Sea. Several offshore HVAC to HVDC converter stations have been constructed and many more are planned in support of the plans to establish OWPs in the German part of the North Sea. The power is supplied from a single or multiple wind farms to one converter station. Each OWP has one (or more) of its own AC transformer stations to provide the HVAC power at the right voltage level for the converter station. Some converter stations are interconnected to provide redundancy in case of failures and some transmission lines are made in sets of more cables and to provide redundancy. The HVDC power is transferred to shore and in some cases up to 80 km into Germany to connect to the main high voltage grid.

The individual transmission lines will not be utilised to the full capacity often due to the nature of the wind energy (fluctuating wind speed). It may be beneficial to have cross-border connections where the transmission capacity can be used for inter-country power exchange.

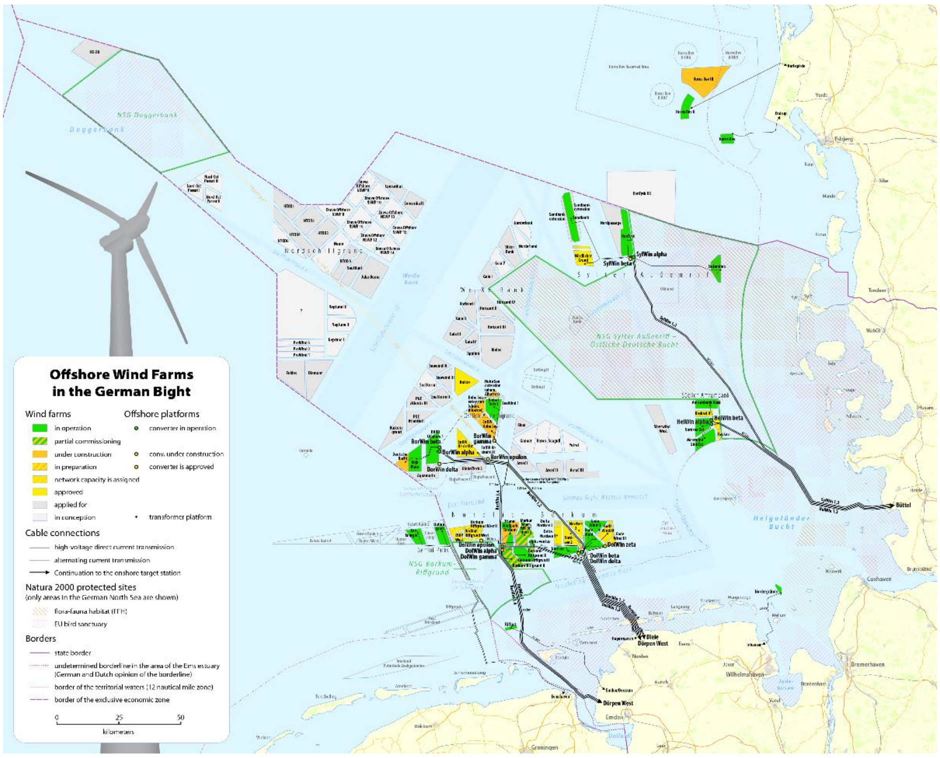


Figure 3-14. Existing and planned OWP areas in German sector of the North Sea

Figure 3-15 shows the existing and planned HVDC connections in Europe.

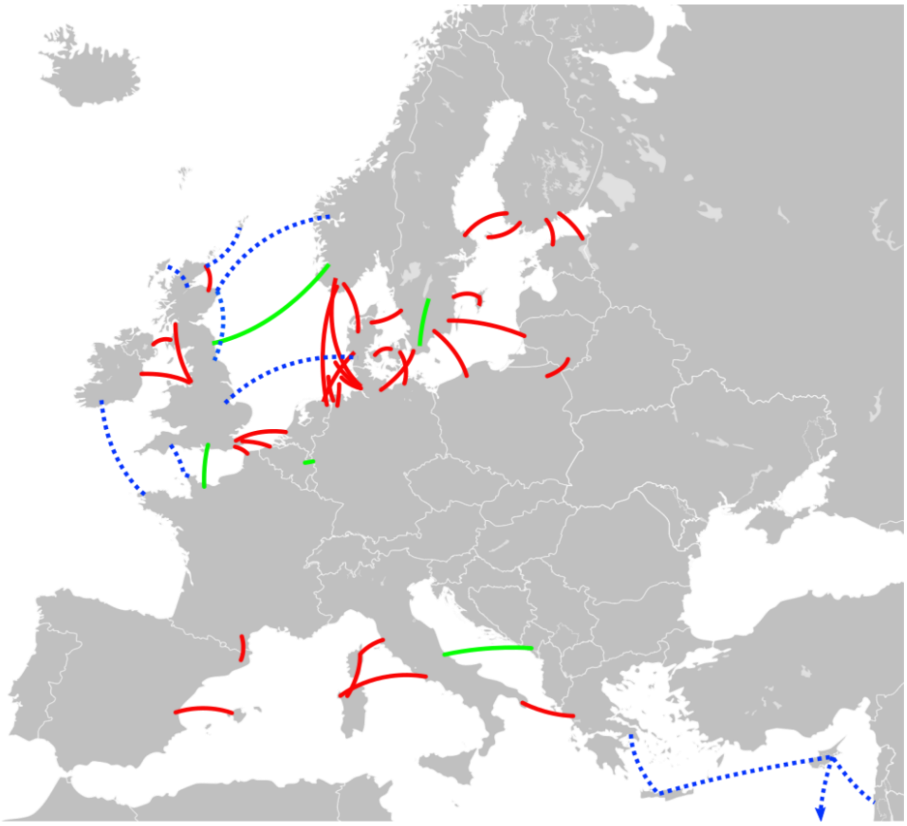


Figure 3-15. HVDC links (Red: Existing, Green: In construction: Blue: Planned)

3.4.1.2 Kriegers Flak hybrid solution

Kriegers Flak is an example of a cross-border transmission line (hybrid solution) being established in the Baltic Sea between Denmark and Germany. Commissioning happened in late 2020. The interlink will transfer power to shore from the three OWPs (Kriegers Flak (DK), Baltic 1 (D), and Baltic 2 (D)); it can also act as a transmission line between Denmark and Germany. The HVAC voltage at connection points is 220 kV in the Danish sector and 150 kV in the German sector. A converter station is in Germany to allow for variation in the grid frequency between the connection in Denmark and Germany. It was originally planned to make an interconnection to Sweden, but this was not included in the final project. Technical character and planning issues are among the reasons for this. One major issue is that the plan to establish an OWP in the Swedish sector of Kriegers Flak has been stalled for the first coming years.

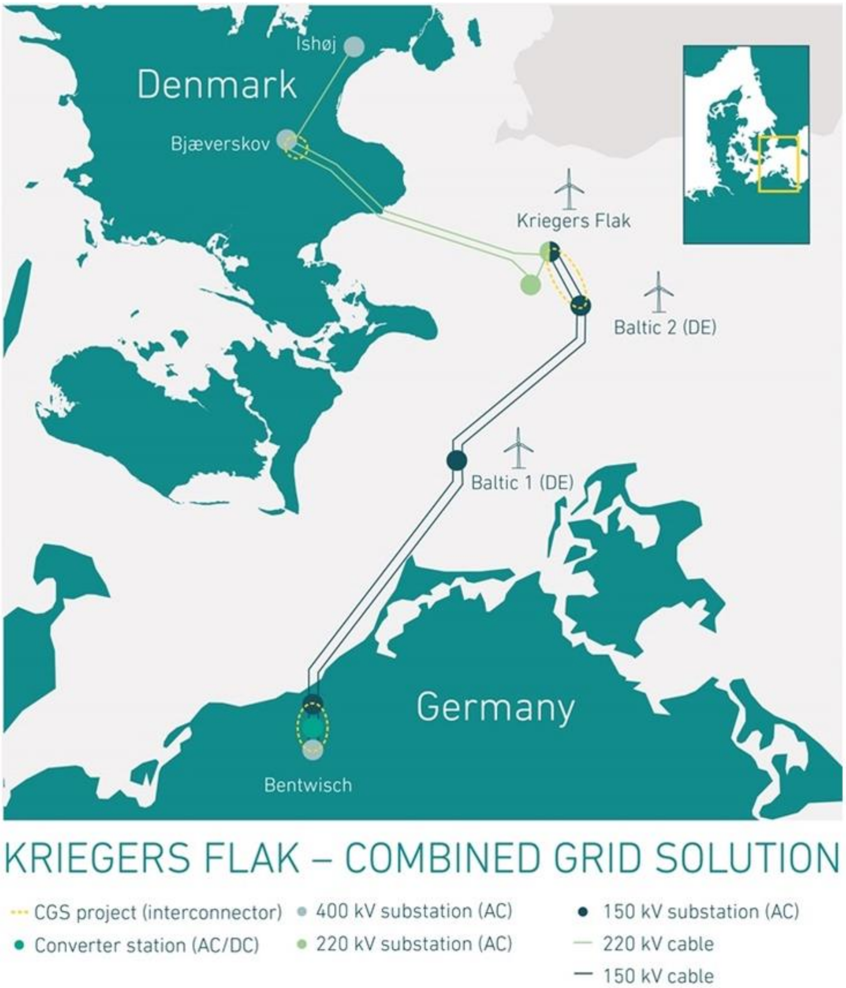


Figure 3-16. Hybrid solution (Type A ref.) between Denmark and Germany *(Source: eneginet.dk)*

The Kriegers Flak offshore wind farm projects and the establishment of the interconnector between Germany and Denmark is demonstrating the even this barrier can be handled and a solution provided, despite the different country specific technical solutions and requirements.

3.4.2 Planning stages

Planning of hybrid solutions are separated in two planning regimes:

- Overall strategic planning
- Project related planning

Without the overall strategic planning and cross-border corporation, the individual hybrid project will be difficult to establish, and the gross benefits of the hybrid solutions will be difficult to harvest.

Transmission lines and local power converting units are essential for the successful implementation of strategic plans and agreements for the overall hybrid installations in the North Sea wind farms. All countries around the North Sea have plans for OWPs and transmission systems. A significant portfolio of projects is already constructed or in the process of construction; without a more formal joint EU approach towards promoting hybrid solutions current development will likely continue and only few future examples of hybrid solutions will be developed. Kriegers Flak has required agreements between the national authorities and the involved TSOs and ongoing planning discussions for a potential future energy island. To establish the overall strategic hybrid plans and agreements, we recommend forming cross-border forums that include all countries around the North Sea and that have a political support and support from the authority level (national and EU level). We recommend a timeframe of 5 years for providing the first version of a strategic plan and establish agreements. The cross-border corporation must then continue to follow up on the projects, their development, and new/upgraded technical solutions. Local cross-border hybrid solutions can be established if local agreements can be made to cover procedures of regulating the power production, power transport, and prices.

It is assumed that known technology (WTGs, foundations, transformers, converters support structures, and cables) continues to be developed and that new methods of electrical power conversion to other sources and energy storage solutions will be developed. Further, it is assumed that local bases are established in the North Sea and onshore to support the industry. This can be in form of platforms, energy islands, or offshore harbouring facilities where local transport hubs, accommodation, converters, energy storage, and power converting units can be located in a convenient way (fixed or floating). Developers tends to establish their own offshore facilities for each new OWP or interconnector. In the long-term, more streamlining on the facility availability and access to needed resources and equipment can help optimise sector development.

Research programmes should be established to support and facilitate the development of feasible solutions. Further, it is recommended to support preparation of international standards in all aspects of the design, construction, transport, marine operations, installation, and interconnection where these do not exist.

Onshore power distribution facilities are essential. Power must be connected and distributed to the consumers in an optimal way; power connection points located too far inland must be avoided, as laying individual power cables are cumbersome for the projects and the affected landowners.

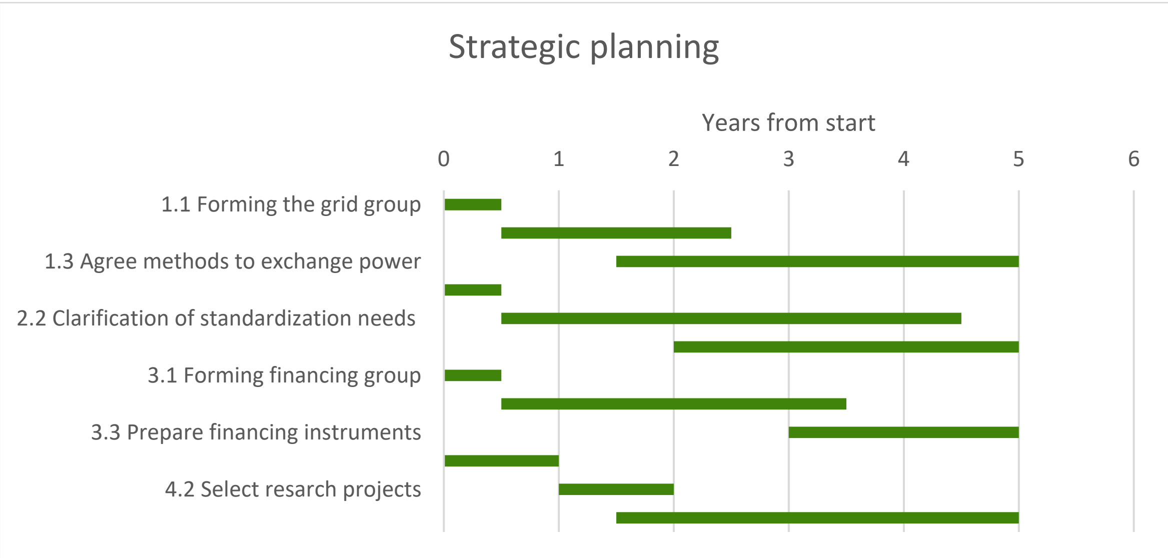


Figure 3-17. Strategic plan

Figure 3-18 describes a typical OWP project development plan.

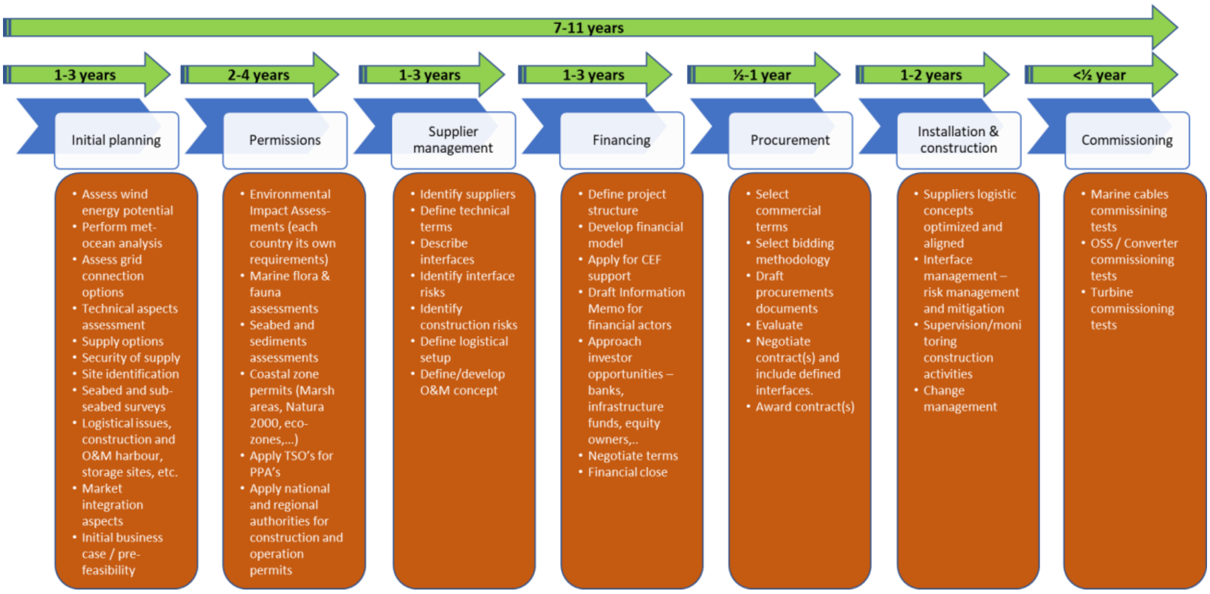


Figure 3-18. Typical OWP project plan

Apart from the described project tasks in Figure 3-18, project ownership frequently shifts from the original developer consortium to other investors during the development phase, the construction phase, or shortly after commissioning. This process can add to the total project period.

Actual project planning will follow the process Figure 3-18 describes, which must be adjusted to the actual conditions. The predefined five hybrid configurations in Figure 3-12 all involve the cross-border corporation and agreements for the power transmission and connection. The time needed for this process is assumed to depend on whether a single country or a two-country connection is made. The complexity of the configurations increases when more independent wind farms are involved and/or when more countries and TSOs are involved, and this adds to the planning and execution time.

3.4.2.1 Initial project planning

Each EU Member State has to develop a Maritime Spatial Planning (MSP) according to the Directive 2014/89/EU. The Directive 2014/89/EU is supposed to be reflected by MSPs in all the Member States latest by March 2021. It outlines the requirements and framework for MSPs and the main goals for how to balance demands for usage of the sea territory while at the same time protecting the oceanic environment.

The MSP is intended to involve relevant stakeholders and plan how, when, and where human activities will interact with the sea environment and how to do it in the most efficient and sustainable way as possible. In each Member State, the MSP will outline sea areas that can be used for environmental protection and preservation, oil & gas extraction, seabed mining activities, fishing, aquaculture activities, shipping, offshore energy activities, and cabling and pipe transport corridors. It will also note how to handle heritage sites identified during marine activities.

The principal rationales for the MSP Directive implementation are the following:

1) Protect the marine environment.

2) Increase Member State cross-border corporation in areas as energy (grid development, pipelines, power cables), telecommunication cables, shipping routes, fishing areas.

3) Support and ensure more transparency and predictability for financing activities.

4) Reduce conflicts or providing guidelines for conflict handling between Member State, between authorities in different Member States, between various sectors operating at sea.

5) Create synergies between countries and sectors for the development of the marine economy.

Individual Member State's MSP must be coordinated with the other North Sea Member States so when all MSPs are ready by March 2021, one can expect maritime spatial planning for the whole North Sea covering all marine activities and all interactions between land and sea. Each MSP focusses on the Member State's own territorial waters. However, the directive requires each Member State coordinate and consult with relevant other Member States and their authorities, creating alignment for common cross-border activities like shipping routes, pipelines, power interconnectors, and telecommunication cables, as well as other activities with joint interests.

The initial planning activities for OWP can be initiated based on the MSP reservations, framework, and guidelines. Historically, maritime spatial planning has occurred in most Member States, but based on different and more national specific objectives, requirements, and principles, this national marine planning has been the cornerstone of OWP development—taking into account environmental regulation and other marine stakeholder interest.

The initial project planning can be divided into the following three workstreams:

- Pre-feasibility stage
- Feasibility stage
- Design stage

The planning activities must consider the various requirements from the adjacent countries. The following sections describe recommended areas where improvements in timing and/or where specific country requirements can support the hybrid offshore development. The estimated typical periods for each stage depend on how well rules, regulations, and standards are aligned between the affected countries and involved parties.

Initial project planning will benefit from cross border agreements for grid connection, power supply, common rules, and standards. If differences in country-specific rules and regulations are identified and mitigated before the project related stages, it will ease the initial project stages considerably and release sources for the other stages.

Pre-feasibility stage

During the pre-feasibility stage, which typically lasts 4 to 12 months, the following activities should be included and taken into account for Member State's MSPs:

- Overview of all existing and planned OWPs in area of concern, their installed capacity, turbine type, foundation type, year of construction, grid connection, bathymetric conditions in OWP area.
- Gathering information on navigation routes, alignment of existing offshore cables/pipelines in area of concern.
- Collection of available existing information on general seabed conditions, morphology, geophysical conditions, soil conditions, met-ocean conditions in area of concern, wind energy resources.
- Consultations with grid connection agencies, typically the TSOs, and relevant authorities (energy authorities, maritime authorities, energy regulators, environmental authorities) in relevant countries.

- Gathering information on potential connection to present or coming interconnectors, converter systems and other wind farm substations.

- In case of a new offshore transmission grid, analyse potential landfall points for transmission lines and potential for further offshore wind energy development and, in some cases, include the need for storage solutions.

- Up-to-date survey of market for supply of wind turbines.

- Define specific sites to develop new OWPs, and size (range) of installed power, preliminary estimates of overall construction and O&M costs, revenue during period of operation.

- Decide on the connection opportunity, depending on other hybrid solutions in the area, distance to shore, and land-based connection.

- Determine whether the hybrid offshore project will be utility driven or non-utility driven and the implications on the level of project development needed, risk imposed on the stakeholders, and the timeline.

- Preparation and issuance of a pre-feasibility report.

In the pre-feasibility stage, easy access to relevant data will speed up the process significantly. Additional common or aligned power regulation rules will be needed.

Feasibility stage

The feasibility stage, which typically will last 6 to 18 months, should include the following activities:

- Definition of investigations, surveys, and studies to be undertaken for each selected specific offshore hybrid wind system. Geophysical, met-ocean, bathymetry, seabed conditions, geotechnical drillings at selected positions.

- Execution of all relevant surveys and investigations.

- Preparation of reports on investigation and surveys, including presentation of results and conclusions.

- Define layouts of OWPs (turbine size, inter-array cabling, foundation type, grid connection, voltage levels), estimate related construction and O&M costs, revenue during period of operation.

- Assess conflict points to navigation routes and offshore cables/pipelines.

- Market analysis for funding, grid connection, selection of turbine and foundation types, execution of financial cost-benefit analysis, estimation of optimum size of facility, possible need for peak production storage facility.

- Preparation of elaborated feasibility report, with reporting on relevant underlying sub-studies.

- Discussions of the Feasibility Study with relevant authorities and agencies.

- Decision-making and selection of OWP layout and sites for detailed design.

Design stage

The design stage, which typically will last 6 to 12 months, should include the following activities:

- Definition of detailed investigations and surveys to be executed (subjects as in the feasibility phase, but now more detailed investigations) with increased coverage of surveys, especially UXOs (if required) and geotechnical drillings
- Execution of detailed investigations
- Reporting on detailed investigations
- Preparation of scope of work, activities to be undertaken, installation plan for each subject to be considered (site office and site activities, foundations, turbines, inter-array cabling, grid connection, environment, O&M), assessment of project and installation risks, estimates for construction, and O&M costs for each relevant subject.
- Preparation of detailed design report, evaluation of installation methods with elaborated financial cost-benefit analysis, as a basis for decision-making on construction.
- Discussions of the detailed design report with relevant authorities and agencies, obtaining authorities' approval.
- Decision-making.

3.4.2.2 Permission stage

The permission stage will be initiated during the pre-feasibility and feasibility stages under the planning sub-task. It will be more detailed and will follow a formalised approach depending on the national requirements. The permission stage varies from country to country and will be assessed as part of the project analysis and recommendations as:

- Environmental Impact Assessments (each country has its own requirements) to be finalised and approved by national authorities
- Part of the EIA further studies of birds, marine mammals and fish, and their breeding seasons to be assessed and needed restrictions outlined for each relevant country in a hybrid solution
- Seabed and sediments assessments
- Coastal zone permits and construction principles in these zones to be verified with relevant authorities (Marsh areas, Natura 2000, eco-zone)
- PPA condition talks with relevant TSOs including supply security, applicable grid codes, PPA tariff principle including compensations for lost production/transmission
- Approach other grid and pipeline operators for approval of access to initiate construction works
- Apply national and regional authorities for construction and operation permits
- Supplier management stage

The supplier management sub-task will focus on having the right supplier basis to work with, as constraints with these will often delay the processes with seabed and sub-seabed surveys, UXO surveys, borehole surveys, installation of foundations, tower, nacelles, blades, OSS jacket, and topside:

- Identification of suitable installation vessels
- Pre-negotiations with operators
- Pre-reservation agreements
- Lease agreement

3.4.2.3 Financing stage

Selecting the most appropriate model for project financing structures is a key to success when supporting the development of hybrid offshore wind investment. Local market conditions in the affected countries must be considered in off-balance sheet funding or developed project financing. More formalised contracting principles have begun using the EPCI contractual setup (engineering, procurement, construction, and installation), limiting the financial risks. This development reduces the financial risks, supported by the fact that offshore wind projects have become more modular and that hybrid offshore solutions will introduce flexibility with more offtakers of the power produced so there is less dependence of one market and one tariff structure.

Financiers prefer long-term PPAs and may expect offtakers to take on the system imbalance risk associated with the variability of renewable energy production, a development generally becoming more common. We examine how to optimise and support this development, where hybrid solutions will act as risk spreading solutions and where the inclusion of storage facilities (pumped storage, batteries, other) can support the generation efficiency. Storage facilities improve the financial viability by providing high priced power during peak demand period and storing overproduction in high wind periods or during required curtailment period.

3.4.2.4 Procurement stage

The procurement stage will last minimum 6-9 months and will probably tend to be on the long side with offshore hybrid wind solutions, as they are more complex projects. The procurement stage does not depend on specific national requirements and regulation as procurement processes already follow international stated standards and EU regulation in the offshore sector. This stage includes the following:

- Preparation of tender strategy and tender documents, and tender timeline
- Issuance of tender documents to tenderers
- Tender period with clarification of questions from tenderers
- Tender submission
- Review and evaluation of received tenders, presentation and negotiation meetings with tenderers (this may include submission of revised tenders during the process, dependent upon selected tender procedure)
- Selection of preferred bidder(s), negotiations with these
- Award of Contract

3.4.2.5 Construction stage

The construction stage will last approximately 1.5-4 years, depending on the size and location of the facility and the complexity of the hybrid solution. This timeframe also accounts for weather delays. Every project will be different and the framework for these processes will follow international standards and be included in the agreements between the asset owner, the EPC/EPCI contractor, other contractors, and the owners engineer. The construction stage will depend on how the procurement packages are defined (timewise and in complexity). The more packages the more time to assumed for the construction phase and the more focus on interface management. The elements below represent the primary focus of this stage:

- Suppliers logistic concepts optimised and aligned, this will differ from type of hybrid project
- Interface management, risk management and mitigation, this will differ from type of hybrid project
- Supervision/monitoring construction activities
- Change management

3.4.2.6 Commissioning stage

Commercial operation will begin in the commissioning stage, when the assets are tested for their operational ability and compliance to the design criteria and the national grid code standards. The commissioning test is also a prerequisite for the takeover, which initiates the warranty period (typically 5 years).

Some elements in the technical standards, the environmental requirements, the marine licensing, and the landfall crossings are subject to different legal modalities in various Member States. Integrated sequencing will allow for adaptation of these variations. Other parts are covered by present international standards adopted in the countries and will be part of the sequencing.

Several of processes during the planning, tendering, and construction stage will be the same for the five configurations. For the feasibility and design of solutions, differences will occur when it comes to the environmental elements.

3.4.3 Interaction between EU, Member States, and TSOs

On the government side, the overall planning of hybrid assets is ongoing and continuous. At present, various factors drive the planning, which are likely to change over time due to the ongoing climate, commercial, and political prioritisation at EU and national levels. An exact plan for planning processes cannot be made and it is likely that some of the stages are ongoing in parallel. An assessment of some of the few hybrid solutions or hybrid-alike approaches already implemented illustrates that scheduling differs based on the decision processes and the project at hand. Additional analysis is needed on the appropriate governmental planning and on the interaction between the various related governmental institutions.

The main processes, as seen from the governmental and EU perspective can be illustrated with the following steps:

Figure 3-19 Governmental and authority processes moving in the direction of hybrid assets

3.4.3.1 Typical lead times

The following lead times where experienced in three cases related to hybrid assets:

- **Offshore HVDC:** The technology behind today's HVDC solutions were developed for interconnectors with land-based HVDC stations during the 1960s and onwards, even the base HVDC technology has more than 100 years behind it. In the 1990s, the first ideas emerged for offshore solutions to the new offshore wind farm industry and the future need for such solutions were identified. Around 2000, the industry and the TSOs realised the need caused by rapid offshore wind development. From 2005 to about 2010, the planning of HVDC solutions began. In 2010, the first offshore HVDC was installed, and in nine have been installed over the last decade. The national TSO has been the key-stakeholder in this process, along with the largest manufacturers on the global scene.

- **Kriegers Flak Offshore wind farm:** The idea for a large offshore wind farm in the Baltic Sea, where the sea territories between Germany, Denmark, and Sweden meet, originated in the mid-late 1990s. The three countries realised a technical issue with different electrical technologies and plans were developed on a TSO and governmental level. In 1998, discussions initiated a joint third-party wind farm with electrical connection to all three countries. The solution materialised in 2005, and a cross border connection was included between Germany and Denmark, but not Sweden. From 2010-2012, the project planning and EIAs were initiated. From 2012-2014, the project developed further, ending with a MOU in 2014. National decisions were made and the official approval on governmental level of the project is slated for 2021. The project will be commissioned and include a Danish and a German offshore wind farm, a HVDC converter station, and (from that) two export cable solutions—one to Denmark and one to Germany. The HVDC converter and the export cables can also be utilised for direct connection between the two countries.

- **Energy islands in the North Sea:** In 2000, a group of TSOs and research institutions exchanged ideas and investigated future optimisation options for the offshore wind industry. The idea exchange focused on future optimisation needs and needs for integration between the North Sea region Member States. From 2000 to 2017, there were ongoing discussions and development under the auspices of the TSOs. From 2017 to 2019, more detailed planning focus and signing of MOUs occurred. The commissioning of the first energy island is planned for 2030-2035.

The three examples above illustrate that the lead time from needs identification to commissioning can be from 20 to 30 years when developing new, complex solutions involving several Member States. Also, these examples demonstrate that the main drivers for the planning and development are the organisations having the need and the capacity to develop such solutions and with the ability to involve the industry in the process. Greater involvement of governmental institutions could have accelerated the progress. The Kriegers Flak project is primarily where governmental institutions have been involved during the solution development and planning phases.

3.4.3.2 Needs identification

- **EU:** The European Commission estimates between 240 GW and 450 GW of offshore wind power is needed in 2050. The EU has committed to develop offshore wind energy and explore Europe's wind energy resources. The offshore wind farms and wind hybrid assets are key to reach the Von-Der-Leyen Commission's ambitions to reduce greenhouse gas emissions to net zero by 2050. From an EU perspective, parts of the security supply, lowered energy costs, and social security can be reached through a more cost-efficient and sustainable approach that focusses on offshore wind farms by implementing wind hybrid assets.

- **Member States:** The countries bordering the North Sea have ambitious climate policies and are working towards increasing green energy supply from renewable energy sources. This will benefit the infrastructure of the North Sea countries and meet the public's demand for more sustainable energy supply from renewable sources. However, national climate ambitions differ, as do their legal and financial support schemes for different technologies and road maps towards the climate neutrality. These differences can block decision-making and corporation on hybrid schemes.

- **TSOs:** Having a profitable and sustainable business from hybrid assets is also of high interest for the TSOs, as it meets the increasing customer demand for green energy and makes the energy sector more sustainable and cost-efficient in the long-term. The issue for the TSOs might be the high cost entrance barrier, as the financial requirements are high for hybrid solutions.

3.4.3.3 Ideas development

- **EU:** Politically, legislation and political attention can accelerate and initiate the development of wind hybrid assets in the North Sea region. EU funding of research programmes and national support initiatives can accelerate the technology of wind hybrid assets and push the energy sector in a more sustainable direction. The investment need is high for hybrid solutions to pave the road for 240 GW to 450 GW offshore wind—the present offshore HVDC solutions implemented have a financing level between €1 billion and €1.5 billion per GW. In addition, the options to include hybrid assets in the TEN-E regulation and PCI process, and provide funding under the CEF, support the development further.

- **Member States:** Dialogue between the North Sea region Member States can be supported in working groups formed under EU and be used for knowledge sharing, idea generation, and cross-border cooperation. Although such organisations have been in place for a while, the drafting of Member States maritime spatial planning and North Seas Energy Cooperation drive ideas around hybrid asset development forwards. In addition, national research programs and cross-border research agreements can benefit and accelerate the development of the technological solutions.

- **TSOs:** The technical solutions and development of grid net strategies will be carried out by the TSOs through participation as partners in research programs, which can be supported by national and international green energy research funding programs.

3.4.3.4 Solution development

- **EU:** To create robust solutions regarding hybrid wind assets in the North Sea region, technical support from research programs is fundamental. The RED (2018/2001/EU) was revised to simplify permission processes and support the development of renewable energy projects. The Directive also addresses the public's concerns and respects environmental standards.

- **Member States:** Permissions can be issued by the relevant authorities (typically the related ministries and their executing bodies) for the pre-investigation, construction, and maintenance phases. Considering the potential environmental impacts and involving the public through public hearings and transparency in the planning process is key to success for the projects. These processes deviate between Member States and so do their timings, so a more coordinated approach would be beneficial for a smooth process and will probably require intervention from the EU or a stronger involvement of NSEC.

- **TSOs:** The TSO's role in research programmes are central as they are close to customers and have local knowledge on how to implement technical solutions. The TSOs should be involved when developing the legal framework and the technical standards. The Kriegers Flak project proved that the difference in national technical standards can be solved, but EU and Member State support to develop solutions will probably speed the processes between the TSOs.

3.4.3.5 Project agreement

- **EU:** The EU can support the development of standard framework agreements between the Member States and TSOs and facilitate agreements that are in-line with EU legislation and planning policies. The EU can also ensure that the framework agreements consider relevant environmental, socioeconomic, technical and climate aspects, and that the public and other relevant stakeholders (interests of other stakeholders with direct or indirect interest in the sea and marine environment) are involved during the different phases.

- **Member States:** Energy authorities need to coordinate and agree on the content of the understanding and determine how to ensure involvement of the relevant stakeholders to establish MOUs between Member States.

- **TSOs:** National energy authorities can coordinate and clarify MOUs between TSOs and Member States. A cross-border framework for these MOUs will improve the processes and align the solutions so new hybrid solution can built on the foundation of present projects.

3.4.3.6 Planning

- **EU:** Environmental regulation from EU legislation, e.g. Marine Strategy Framework Directive (2008/56/EC), Habitats Directive (92/43/EEC), and Water Framework Directive (2000/60/EC), form the basis when planning offshore infrastructure in the European Union. Public consultation and stakeholder involvement are crucial when planning offshore infrastructural projects. A more joint approach to the approaches between the Member States and the EU and implemented via hands-on guidelines based in EU legislation might support the planning process and make it more transparent for projects involving multiple Member States, as will be the case with hybrid solutions.

- **Member States:** Marine spatial planning, HV grid planning, and EIA processes should be clarified and coordinated on authority level between the involved Member States. In the best case scenario, only one EIA and one planning process should be needed, considering hybrid solutions covering more countries. From an investor's point of view, a more united EIA and planning process and united MOUs ensure higher trustworthiness (and bankability) in the solution.

- **TSOs:** The TSOs will take care of the grid planning as they have the required technical knowledge and responsibility in this area. When dealing with hybrid solutions, the national HV systems/grids will not be directly impacted of an offshore hybrid solution, except that high amount of energy will be injected to the HV grid at new locations. TSOs need the time to incorporate the energy offtake to their grid and incorporate it into their ongoing grid planning.

3.4.3.7 Licensing

- **EU:** The European Commission could develop an EU-based license framework to be used by the project stakeholders. The license framework could be a pillar in a general EU framework for project development, MOUs, and EIAs between the Member States and the TSOs.

- **Member States:** The individual Member State will implement the license framework agreement into national legislation. When entering into agreements between Member States, a unite framework will make the process smoother.

- **TSOs:** The TSOs will offtake the project based on the national legislation and funding.

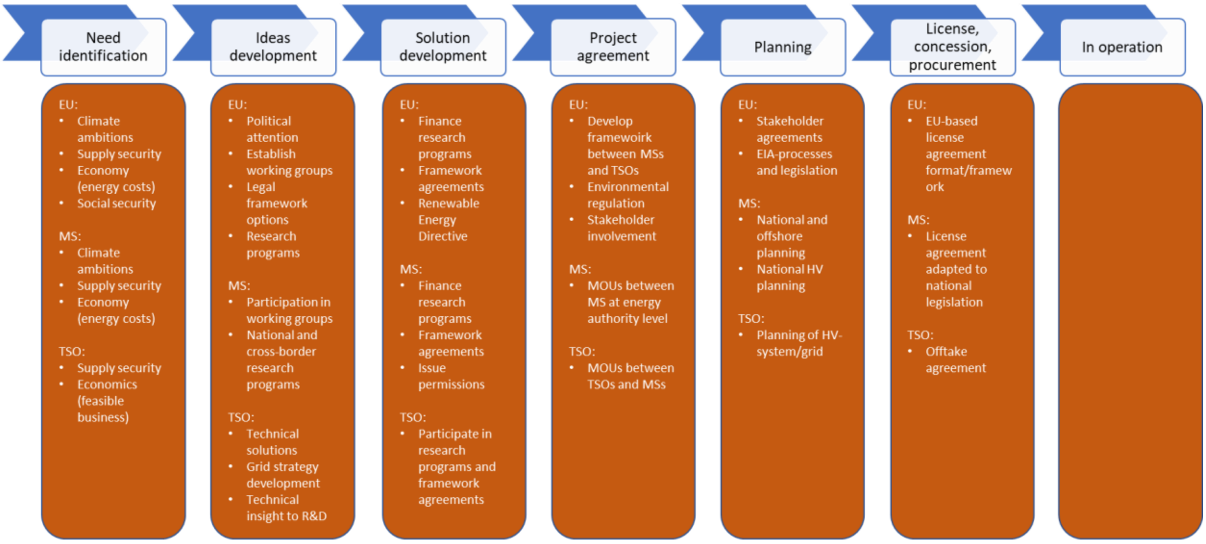


Figure 3-20. Governmental and authority processes and steps supporting the development of hybrid solutions

The commissioning stage begins the commercial operation, where assets are tested for their operational ability and compliance to the design criteria and the national grid code standards. The commissioning test is also a prerequisite for the takeover that initiates the warranty period (typically 5 years).

Some elements in the technical standards, the environmental requirements, the marine licensing, and the landfall crossings are subject to different legal modalities in the various countries. Integrated sequencing will allow for adaptation of these variations. Other parts are covered by present international standards adopted in the countries and will be part of the sequencing.

Several processes during the planning, tendering, and construction stages will be the same for the five configurations. For the feasibility and design of solutions, differences will occur as well as when it comes to the environmental elements.

3.4.4 Project plans

Table 3-17 includes the differences in the planning process of the five predefined hybrid configurations. It also defines the common planning stages. The assumed differences of the project stages are elaborated for each hybrid configuration.

Table 3-17. Overview of planning stages

Id.	Planning stage	Explanation
1	Consent and investment	Initial phase where the consents are obtained, and the investment decision is made.
2.1	Interconnection, Planning	Planning of interconnection (cables and substation[s]) and preparation of agreements to distribute the power.
2.2	Interconnection, Tendering	Tendering of the interconnection (cables and substation).

Id.	Planning stage	Explanation
2.3	Cables, Fabrication	Fabrication of onshore and offshore cables and connectors.
2.4	Substation, Fabrication	Fabrication of substation including transformer and electrical components. Manpower facilities, short-term accommodation and a helicopter platform are often also located on the substation. Fabrication of onshore grid and connection equipment.
2.5	Cables, Installation	Installation of onshore and offshore cables. Cables shall be protected (placed in the ground), this is done in various ways (plowing, jetting, digging) depending on the ground conditions.
2.6	Substation, Installation	Installation of onshore and offshore substation. Installation of the cables into the substation.
2.7	Interconnection, Commissioning	Testing and commissioning of the interconnection.
3.1	Generation, Planning	Planning of the power generation and eventual power conversion or storage devices. Selection of sizes of wind turbines and eventual also the foundation types.
3.2	Generation, Tendering	Tendering wind turbines, foundations and eventual power conversion, or storing devices.
3.3	WTG Foundations, Fabrication	Fabrication period for wind turbines.
3.4	WTGs, Fabrication	Fabrication period for foundations. Typical monopiles but jackets are getting more common for larger wind turbines. Other designs are also used.
3.5	WTG Foundations, Installation	Installation of foundations.
3.6	WTGs, Installation	Installation of wind turbines. Installation of cables into the foundation and wind turbine.
3.7	Generation, Commissioning	Testing and commissioning of wind turbines.

The timeframe for the five predefined configurations includes many similar processes. The number of these processes and their complexity will add to the total time. An interconnection between two countries will take more time than if the connection is made in one country. If more wind farms are included, this adds to the complexity. A large variation in the duration of the individual phases are observed in executed projects. Factors such as experience, commitment, clever planning, robust technical solutions, and favourable market conditions can shorten the total project time and lack of the same can have drastically effect on the project time and costs.

3.4.4.1 A. Combined grid solution

Two wind farms are in separate countries with a cross-border interconnection to the main grid in their respective countries. Spare capacity may be used for inter-country power transfer.

The two wind farms can follow independent project planning and interconnect when it is convenient in the project's plan. It is assumed that the full effect of the OWP can be supplied to the home country. The main technical challenges of the interconnection may be differences in the voltage level and the grid frequency. The power transferring capacity of the interconnection and the power lines are essential for the interlink's feasibility. Financial challenges include the agreement of shearing of capacity of the power lines. It is assumed that the feed in-tariffs are determined on the free power market. Local, country-specific support regimes will be difficult to handle, especially if different tariffs are for power from WTGs and other tariffs are for the transferred power.

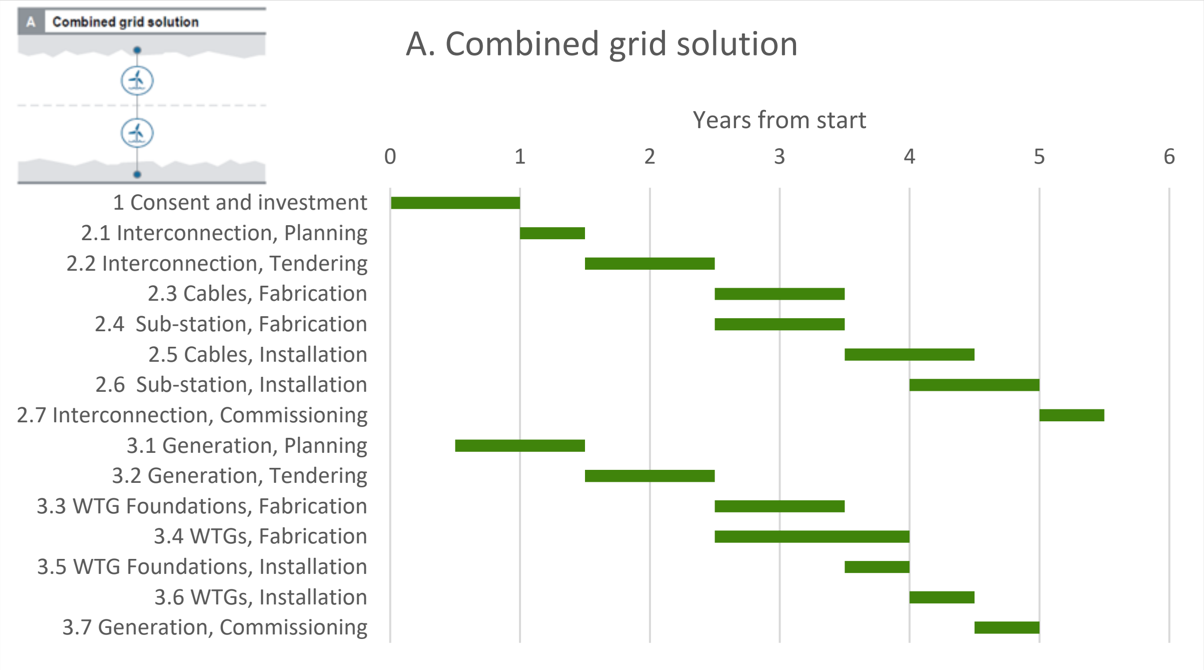


Figure 3-21. Time plan, A. Combined grid solution

3.4.4.2 B. Modular grid

Two wind farms are located in one country and a third wind farm is in a neighbouring country. The wind farms are connected to a common offshore station (likely a converter station) that are connected to the main grid in the country where the offshore station is located. The individual wind farms will likely be connected by offshore transformer stations to the converter station to supply high voltage power.

The two wind farms in the prime country can be planned and constructed according to country-specific rules. The third wind farm in the neighbouring country shall be designed to supply power in accordance with the neighbouring country regulations. Country-specific support regimes may apply.

Planning depend on construction of the common offshore station.

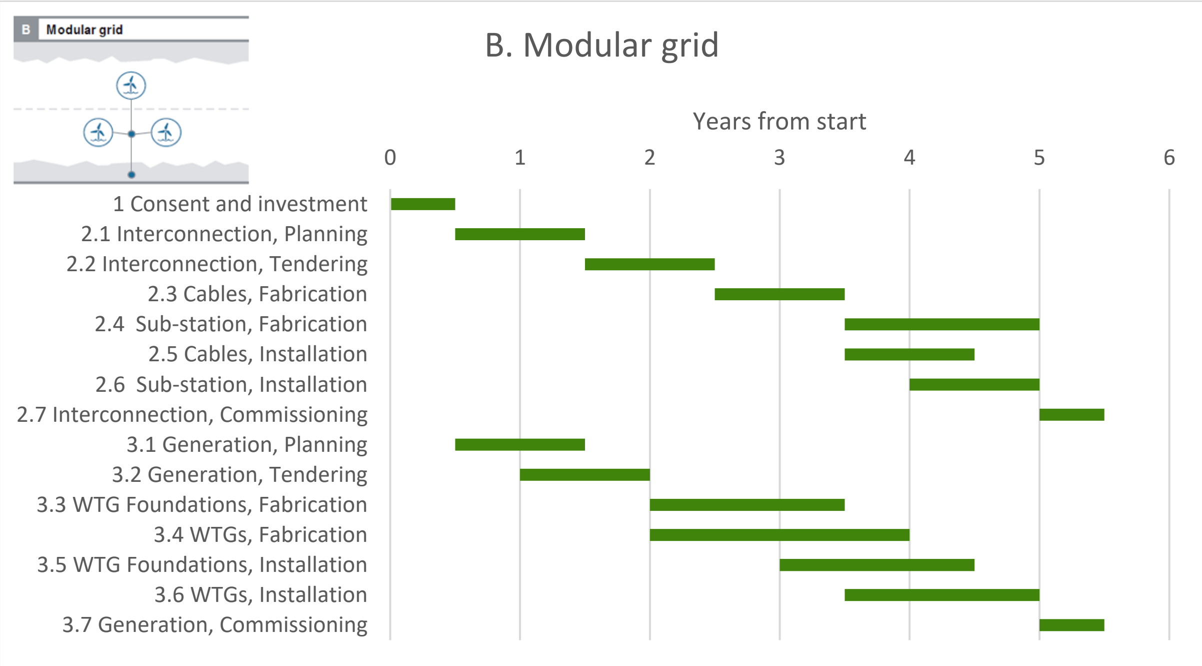


Figure 3-22. Time plan, B. Modular grid

The plan for case B can benefit on a grid connection made in one country only. In this case, the connection details will be determined in the country where the connection is made. Three OWPs shall be constructed and it is assumed that they can be made in parallel. Construction of the OWP in the neighbouring country may lag behind the others and the timing likely need to be more robust.

3.4.4.3 C. Interconnector tie-in

A cross-border connection is made; two wind farms are located in separate counties and connected. The purpose of the interconnection is the cross-border interlink and it is assumed that the capacity of the interlink is enough or more than enough to transfer the power from the OWPs in any direction.

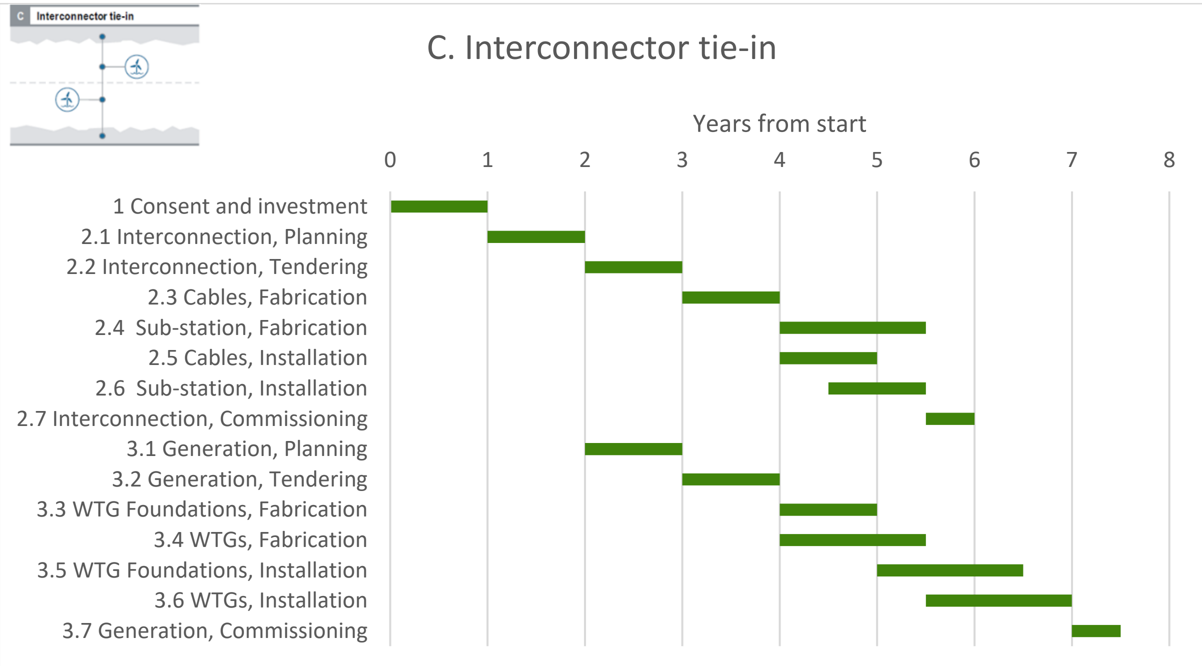


Figure 3-23. Time plan, C. Interconnector tie-in

In case C, the time plan is affected by the inter-country connection where agreements of grid requirements, voltage level, feed-in conditions, and price regulation are solved. This agreement is similar to case A. However, it is assumed that the connection is assigned for higher capacity than produced by the OWPs. A HVAC/HVDC converter system is likely to be included in the solution.

The OWPs can only be constructed after the interconnector is established. The two OWPs will likely be constructed by two different organisations. In the present plan, it is assumed that tending, fabrication, and installation of the two OWPs can be made in parallel.

3.4.4.4 D. Offshore hub

A power hub (likely a converter station) is located near to the border and several OWPs are connected to it. The OWPs can benefit from sheared services at the power hub. An interconnection is made between two countries passing by the power hub.

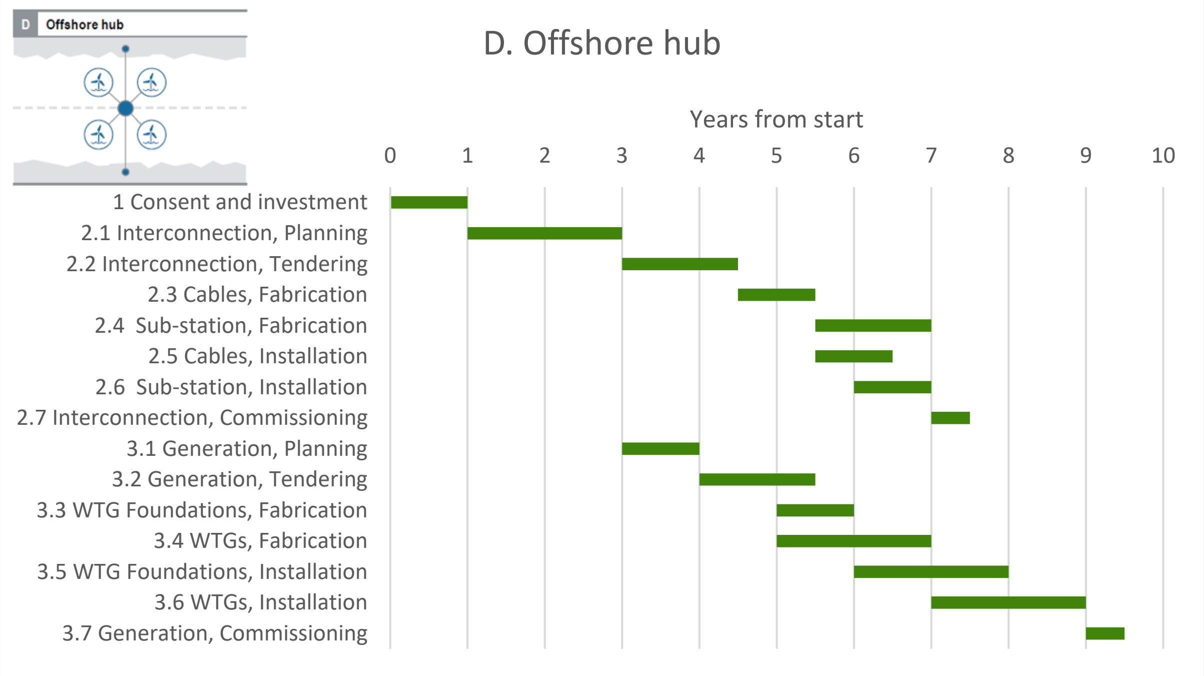


Figure 3-24 Time plan, D. Offshore hub

In case D, the time plan is affected by the inter-country connection where agreements of grid requirements, voltage level, feed-in conditions, and price regulation shall be solved. This agreement is similar to case A and C. It is assumed that the connection is designed for higher capacity than produced by the OWPs. A HVAC/HVDC converter system is likely included in the solution.

Four OWPs shall be constructed, eventually by different organisations. In the present plan it is assumed that tending, fabrication, and installation of the four OWPs will delay the total fabrication and installation due to a large amount of construction and installation work.

3.4.4.5 E. Neighbour OWP

A wind farm is connected to shore in a neighbouring country.

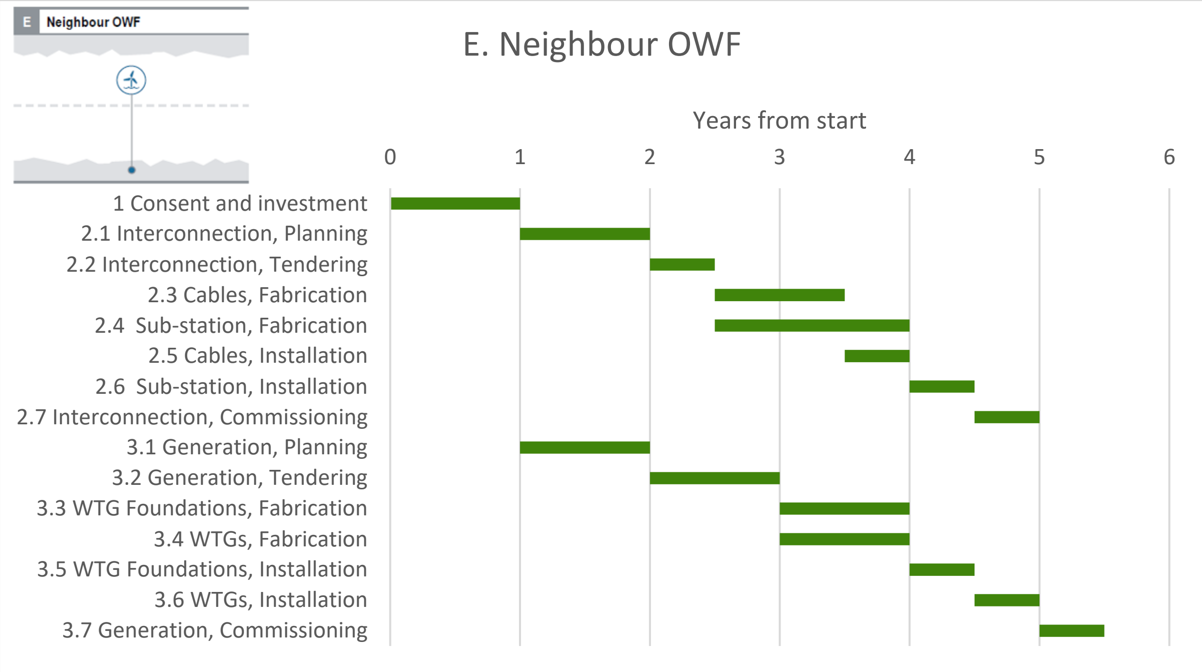


Figure 3-25. Time plan, E. Neighbour OWP

The time plan for case E benefits as the grid connection is in one country only. The connection details will be determined in the country where the connection is made. The case is similar to case B but simpler. Only one OWP shall be constructed.

3.4.5 Conclusions and lessons learned

Coordinating OWP plans, interconnector planning, grid connection regulations, and standards are essential for facilitating and reducing the time schedules for the initial project planning for hybrid solutions in the North Sea. The coming MSPs from each Member State (where the marine activities and planned and coordinated internally and cross-border) will pave the way for a more robust foundation for OWP development. Broadly, it should be considered whether the same level of planning on the Member State's power systems and their development can contribute to the more efficient development and operation of EU power grids. Based on the few examples for hybrid solutions—the converter systems in the German waters and the OWP and interconnector solution through Kriegers Flak in the Baltic Sea—the national alignment of planning practices, grid standards, and environmental permitting processes are crucial for cost-efficient planning, design development, cross-border agreements, and operational modes. Cross-border initiatives are established within the following fields:

- Planning of OWPs
- Planning of onshore high voltage grid
- Planning of inter country connections
- Common electrical requirements
- International standards adopted to EU level

- Research programs in the following:
  - Development of standards for offshore grid connections
  - Development and planning of hybrid solutions
  - Cross-border modalities for the development of energy hubs

For phases covering financing, procurement, and construction, most of the rules for offshore assets, financing, and construction are well in place and provide significant experiences for the oil & gas sector and the offshore wind sector. In these areas the market players do have a ruleset to follow and act effective and with time and costs in focus. On the other hand, the operational and maintenance phases are mostly performed on an asset-by-asset operation with individual setups for nearly all offshore assets. A long-term focussed development towards several operational hubs can support the cost-efficient operation of an expanding number of OWP capacity and hybrid solutions in future.

The five hybrid configuration plans are assumed to vary considerably from 5–10 years related to the complexity of the configuration. A country-to-country connection is complicated to establish with existing regulations. Technical issues including voltage level, frequency synchronisation, and power quality are among the issues where joint solutions could support smoother, more efficient planning and development. Joint solutions could also use common EU or international standards instead of national standards on the high voltage grid level for the design parameters for offshore installations to reduce the time to develop these solutions and ensure they are more standardised in the long term. Using these standards supports the goal of cost-efficiency in manufacturing, construction, and O&M. Regulatory issues such as support schemes and feed-in tariffs shall also be determined for the actual power export to various grid sections in different countries. If more OWPs are constructed and installed within a short timeframe production and installation limitations can be expected.

By developing interconnectors, lessons learned have been realised on several fronts. While parties have pragmatically solved barriers, coordination is key. Most gain is on the permitting and planning side. However, there are precedents regarding matters that were previously considered unknowns and risks. These include uncertainly regarding legislating cross-border cables, regimes for revenue, planning OFWs, and interconnector capacity (competition), principles for transferring renewable electricity across borders and national green targets, and the impacts on funding.

In an interview, an investor of a UK linked interconnector commented that technology and construction risk (or lack thereof) of interconnectors are well known and do not form a barrier. This has made project financing of interconnectors easier. For instance, the Danish and German grids operate at different frequencies. This has successfully been overcome, as demonstrated by hybrid interconnector project Kriegers Flak. A difference between grid codes in two or more countries on an interconnector no longer constitutes a timing risk or a technical challenge. While still capital intensive, the cost of interconnectors is decreasing, which decreases the cost barrier.

Development of new and upgraded technology moves fast in the OWP sector: Size and capacity of existing WTGs were not available 10 years ago. Cost-effective foundations are developed and expected size limits continuously change. Development and construction of installation vessels has followed the growth in WTG and foundation size. A key factor to support the development is long-term plans and prizing mechanisms that allow the investors to plan for the long term.

Energy islands are among the new ideas on how to facilitate the growth of capacity of the North Sea OWPs. The energy islands or hubs shall be constructed in a feasible and environment friendly way. Further the challenges of providing technical support and service shall be solved in a practical and cost-effective way. This could be in the form of floating installations or installations on jack-ups. Common research programs and pilot projects should be supported.

4. Conclusion

This report revisits the need for a massive scale up of offshore wind in NSEC countries and elsewhere in Europe. We detail the status quo of wind offshore regimes and show that there are a variety of co-existing schemes, none of which appear to outperform each other. However, when cooperating on offshore wind, especially with a view to joint (hybrid) OWPs, Member States will have to determine which regime and underlying characteristics (e.g. market integration vs. lowering cost of capital) they want to apply.

To develop an integrated framework for joint (hybrid) OWPs, the market arrangement needs to be determined. Neither solution (HZ or OBZ) appears to be without challenges and both require legal changes at national and European levels. In terms of the financing of joint (hybrid) OWPs, the OBZ redistributes surplus from producers to TSOs, which likely has to be compensated by support schemes. The increased risk of negative prices remains an important issue for OWP operators in that context.

The cooperation software, the basic project setups, and the support schemes (including site selection, grid connection regime, form of support, and tender design) are not major design and implementation challenges. Choosing or designing a coherent scheme, suitable to the specific project setup, is what is important. Coordinating these elements with the cooperation Member States (and its responsible parties in subordinate entities) is the underlying cooperation challenge.

Another major issue in the deployment of joint (hybrid) OWP is the proper CBA and CBCA. The different components and their assessment have to be paired—namely infrastructure and generation assets. In addition to high level recommendations, we developed detailed technical suggestions on how to coordinate and integrate the previously separate cost allocation approaches. If Member States and TSOs can be convinced that they benefit from a specific cooperation opportunity—by means of proper analysis and compensation and/or because of significant strategic value—they will commit to the intensive decision-making required to realise offshore cooperation.

EU funds may be a key component to encouraging the cooperation efforts of Member States. If substantial and if properly coordinated, the different sources (CEF energy and cross-border RES, EU RES financing mechanism, and potentially even EU recovery funds) may compensate for some of the transaction costs and cooperation impacts (e.g. offsetting lower producer rents in OBZ). These sources may add to the net benefit experienced by the key players involved in offshore cooperation.

In terms of the integrated sequencing for the planning, tendering, and construction of hybrid assets, the lead times of project setups vary considerably (from 5–10 years) related to the complexity of the configuration. While TSOs and Member States have solved barriers, coordination is key to proper sequencing.

Creating an integrated framework for financing joint (hybrid) OWPs is not about making all offshore schemes in NSEC countries the same or about overly complex and sophisticated support scheme designs. It is about understanding the benefits of specific cooperation projects, knowing the options to ensure involved countries benefit from the projects, and then properly coordinating the framework elements in the involved Member States.

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