OFFSHORE TSO COLLABORATION
EXPERT PAPER IV

Balancing costs, benefits and risks for cross-border offshore grids in the North seas

Supporting Europe's energy security and competitive growth through a regional approach to offshore grid development

Executive Summary

Energy security and competitiveness are essential for a future-proof Europe. The North Seas provide an unparalleled source of offshore wind energy, best harnessed not only through radial connections but also through cross-border offshore grids. These grids can supply clean, secure and affordable electricity while improving system optimisation and accelerating decarbonisation. Yet major barriers still impede the realisation of concrete cross-border projects. The European Commission's Grids Package, published at the end of 2025, aims to strengthen coordinated planning and cost-sharing across Europe's energy infrastructure.

This paper presents the Offshore TSO Collaboration's (OTC) recommendations for an integrated regional process for planning, cost-sharing and financing to enable such projects in the North Seas, building on earlier messages from previous papers. Expanding on the OTC's joint planning approach, it highlights innovative yet effective cost-sharing methodologies and flexible financing solutions.

In short: regional cooperation, joint planning to select the right projects, cost-sharing to define country contributions, and a financing framework with the right tools are essential to deliver Europe's long-term ambitions in the North Seas.

Joint planning is essential to unlock the North Seas' offshore potential

Joint regional planning is the foundation for cost-sharing and efficient project delivery. A shared regional planning process improves transparency, strengthens political support, and ensures that investments reflect regional system needs. The OTC has carried out a joint planning exercise, resulting in an updated OTC Grid Map, which identifies promising projects based on jointly assessed system benefits. Governments must strengthen, support and accelerate coordinated regional planning to fully realise offshore potential and move promising projects from maps to construction.

Share costs effectively to secure shared benefits through an innovative, comprehensive methodology

Delivering offshore grid infrastructure requires clear agreements on how countries share costs, benefits and risks. The core principle is straightforward: partner countries contribute in proportion to the benefits they receive, based on modelled projections (ex-ante) and/or observed conditions (ex-post). The OTC proposes that cost-sharing approaches should apply both to sets of projects as well as to individual projects that result from joint regional planning.

We recommend that cost sharing arrangements take both generation and transmission costs into account. For generation assets, only the costs of support schemes should be subject to cost sharing between countries. Although assets may be owned by different entities, the benefits of additional generation and transmission capacity are closely interlinked. Considering all relevant costs ensures a transparent and robust basis for negotiations.

Cost sharing should balance predictability with flexibility. We therefore recommend further developing a mixed cost-sharing approach that combines ex-ante scenario-based elements with ex-post observed metrics. Fixing contributions upfront based on modelled scenarios increases stability and predictability, while adjusting shares to actual benefit distributions allows the framework to reflect changing economic and system conditions.

Early alignment on principles is essential to secure investor confidence and ensure solutions are acceptable to all stakeholders. TSOs, governments and NRAs need to work together to determine the optimal combination of ex-ante and ex-post elements.

Enable flexible financing to mobilise the required investment

Delivering the North Seas' offshore ambitions will require major investment. Mobilising the necessary capital can be supported by clear, predictable, and well-aligned financing frameworks. However, different regulations and ownership models across TSOs shape the available financing solutions, the revenue streams for investors and how risks are managed. Therefore, policymakers must support a flexible financing toolbox.

The key principles for effective financing solutions are to reduce the cost of capital, leverage existing processes and funds, allocate risk appropriately, account for differences in regulation, ownership and project characteristics and catalyse private capital.

A financing toolbox may include public loans, commercial finance, green bonds, guarantees, equity or hybrid instruments, and grants to address funding gaps. Above all, investors need clarity: cost-sharing agreements and regulatory frameworks must be firm and predictable. The revenues for TSOs must adequately reflect the costs and risks of investments.

Commit to an integrated process across planning, cost sharing and financing – and unlock the first projects

Policymakers must act now to turn shared ambition into concrete progress. Aligning planning, cost sharing, and financing can unlock the investment needed for the next generation of offshore infrastructure. This will only be achieved through close collaboration among all stakeholders.

Three essential next steps are:

1. Plan and identify North Seas offshore project sets in a structured, recurring process with stakeholders to select concrete projects for implementation. Accelerate towards agreed projects to enable timely investment decisions.
2. Agree on cost-sharing principles early to ensure transparency and practicality, thereby making it possible to apply the cost-sharing methodology on the first projects.
3. Develop mechanisms for ex-ante fixed amounts and ex-post adjustments in cost-sharing agreements and establish financing frameworks aligned with key principles.

A coordinated regional approach will deliver cleaner energy, stronger energy security, and a more resilient North Seas energy system.

I. Introduction

The North Seas hold immense renewable energy potential that is central for European climate and energy objectives. Binding political commitments underscore Europe's determination to significantly reduce greenhouse gas emissions in the coming decades. The United Kingdom aims for a fully decarbonised power system and a net-zero economy within the same timeframe. Achieving these goals will require balancing rapid decarbonisation with affordability for consumers and strengthened security of supply.

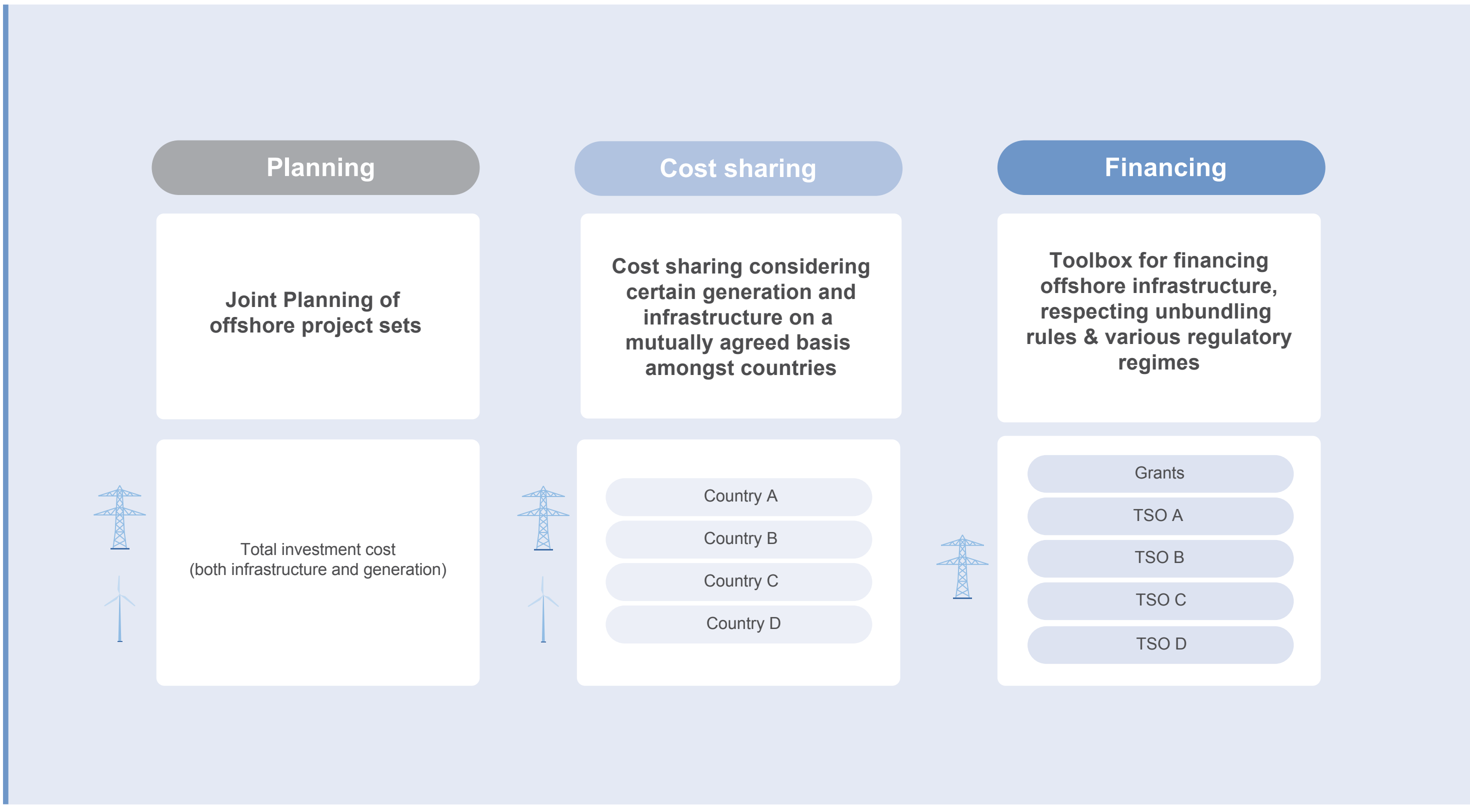
Hybrid interconnectors, which connect offshore wind farms via subsea transmission lines to multiple countries, can provide secure, domestic, and clean electricity while reducing dependence on fossil fuels. Such projects have the potential to optimise electricity dispatch, accelerate decarbonisation, and strengthen energy independence. However, the benefits of these projects can be distributed across many countries. Therefore, realising such projects requires novel approaches to joint planning and benefit-driven cost sharing, as current frameworks often fail to integrate wider regional benefits.

This expert paper[1] delivers the technical foundation to enable governments of the North Seas Energy Cooperation (NSEC) to take key political decisions needed to unlock investment in the next generation of offshore grids. Building on the OTC's joint regional approach to planning, cost sharing and financing (Figure 01), the paper outlines different approaches to cross-border cost-sharing and potential financing solutions.

The OTC's work in this expert paper also serves as a relevant input to the ongoing discussions on the proposed European Grids Package, published in December 2025. Strengthening the role of regional planning in the final legislative framework is essential to reflect shared interests and interdependencies between cross-border offshore grid projects and to align European planning with the specific realities of individual regions.

[1] Previous OTC Expert Papers have progressively addressed different challenges:
Expert Paper I (2023): The Esbjerg Cooperation.
Expert Paper II (2024): The TSO Collaboration.
Expert Paper III (2025): Joint Planning in Europe's Northern Seas.

Figure 01:
OTC's proposal for a joint regional approach to planning, cost sharing, financing and funding



II. Joint sea basin planning as the basis for cost and benefit sharing

Joint planning is a key basis for entering discussions on cost sharing. Given the objectives of the OTC to progress a regional, jointly planned offshore network infrastructure for the North Seas, the need for a multilateral study was identified in 2023. The OTC explores a joint, regional planning process to investigate the benefits of offshore cross-border projects as a coordinated set rather than as individual projects. The process integrates into existing European planning processes, building on ENTSO-E's[2] Identification of System Needs (IoSN) and Offshore Network Development Plan (ONDP), and providing input via project submissions to the Ten-Year Network Development Plan (TYNDP).

The investigation in the first study, a joint Grid Map study, was conducted in the context of existing European frameworks, by aligning on scope, time horizon and assumptions, drawing on ENTSO-E's TYNDP 2024 scenarios ("National Trends+" and "Distributed Energy")[3] and integrating Great Britain's "Future Energy Scenarios". Building on ENTSO-E's Infrastructure Gaps Report[4] and the ONDP as a needs baseline, the OTC developed multiple candidate offshore topologies across hybrid interconnectors and cross-border radials and tested them over multiple climate years and sensitivities to evaluate their robustness. The joint study iteratively screened these topologies for regional socioeconomic welfare, while ensuring consistency with national pathways and acknowledging hydrogen interactions embedded in the TYNDP scenarios. Throughout, the OTC designed the exercise as complementary to the TYNDP/ONDP and maintained close coordination among TSOs from all North Seas countries including the UK.

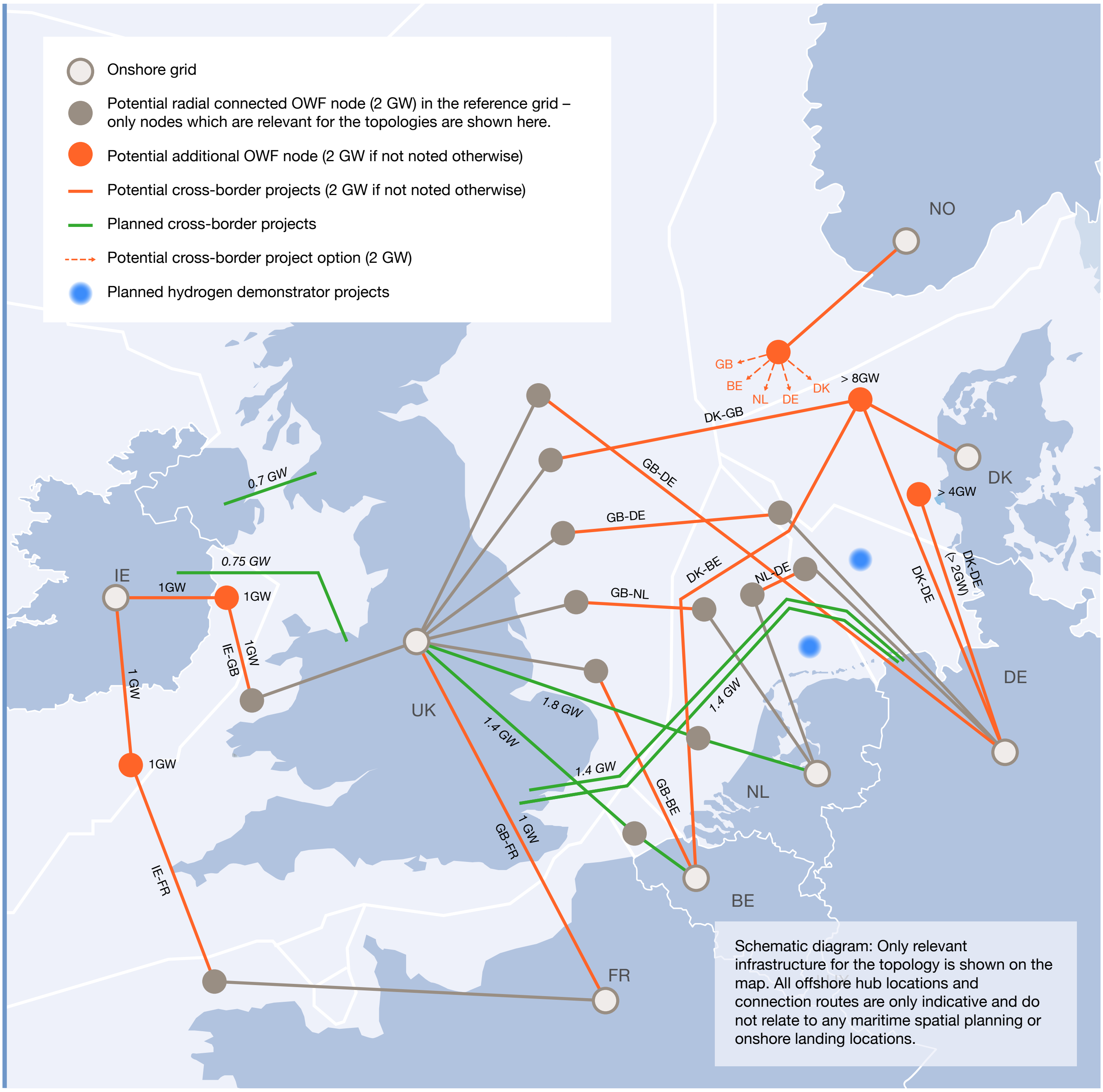
The first outcome was the OTC Grid Map in Expert Paper III (EPIII), which grouped results into promising candidates and candidates to be further investigated. The impact on onshore grid development was not investigated in this Pilot Study.
Simultaneously, the results of this study were used to engage with political

[2] European Network of Transmission System Operators for Electricity (ENTSO-E).
[3] TYNDP 2024 // Scenarios Report – Final Version January 2025.
[4] TYNDP 2024 // Infrastructure Gaps Report / Opportunities for a more efficient European power system by 2050.

stakeholders and national regulators to put this project set into the broader political context. This was done both with individual ministries and the support of NSEC. Additionally, the results of the study provided the TSOs with further information to help them submit new projects or refine existing ones for inclusion in the TYNDP 2026.

Figure 02:
OTC Grid Map 2025 – Second Edition

The following Grid Map is the updated outcome of this joint effort in the Grid Map study (Figure 02). A more extensive description of the considered projects on each border is given in Annex A (Project list).



The Grid Map in Figure 02 is a schematic overview and does not assess or prescribe optimal cable landing points, converter locations, or the specific siting of offshore wind farms. Routes are illustrative and offshore wind areas are indicative. Detailed siting and routing of these electricity infrastructure projects are part of governmental national spatial planning, and individual project and general grid development processes. Only relevant infrastructure for the topologies is shown on the Grid Map. The figure also reconfirms ongoing projects such as Nautilus and LionLink. Unless otherwise specified, the Offshore Wind Farm (OWF) nodes have a capacity of 2 GW. This assumption was made solely for the purpose of this exercise and does not relate to commitments on future offshore tenders.

Next OTC planning cycle process

The purpose of the OTC planning cycle is to identify cost-effective multilateral sets of cross-border infrastructure projects in the North Seas that deliver regional benefits and are supported by respective governments. The OTC looks forward to turning this pilot joint planning approach into a continuous exercise, starting with the next OTC planning process cycle in 2026. This cycle will be as equally embedded into existing European and national planning processes as our pilot effort. Please see Expert Paper III on "Joint Planning in Europe's Northern Seas" and the OTC Cooperation Paper[5] for further reference. Further iterations of the OTC joint planning process will support the investigation of cost-sharing principles that are outlined in the next chapter.

[5] OTC & HyNOS & WindEurope (2025): Strong partnerships for a coordinated perspective on offshore energy.

III. Cost sharing

Joint regional planning can identify offshore project sets that provide region-wide benefits that can extend to EU level. However, the benefits may not be evenly distributed across the hosting countries of all projects, or even other non-hosting countries within the sea basin.

The mismatch between costs and benefits can be overcome by jointly assessing project benefits and allocating costs accordingly on a regional level. To address this imbalance, the OTC proposes a sea basin-level cost and benefit sharing framework to ensure equitable participation and broad support. This decision can be informed by a mutually agreed cost-benefit assessment that builds on joint regional planning. Concerning costs of generation, it should be noted that any cost-sharing methodological proposals by the OTC solely regard the costs of generation support schemes of certain generation, such as Contracts for Difference (CfDs) and not the full cost of all generation assets themselves.

The OTC approach aims to address some critical issues raised by the existing frameworks. Cross-border cost allocation (CBCA) is under the TEN-E regulation[6] and only involves benefitting non-hosting countries that could participate in the costs in a late stage of project development. Sea basin cross-border cost sharing (SB-CBCS)[7] is a high-level exercise providing insights on benefits, but without application to specific projects. The OTC proposes that the Joint Regional Cost Sharing would play a vital complementary role by involving the parties sharing the costs in the project identification (planning) as well as the cost-sharing stage and would ensure a coherent and transparent cost-sharing decision that provides the necessary agency for all involved parties. Figure 03 presents the complementary role OTC envisages for the regional cost-sharing framework.

[6] European Commission Regulation: 'Regulation (EU) 2022/869 on guidelines for trans-European energy infrastructure (TEN-E Regulation).' Official Journal of the European Union L152 (2022).

[7] European Commission Communication: 'Guidance on collaborative investment frameworks for offshore energy projects.' C/2024/4277 (2024).

Figure 03:
Comparison of cost sharing frameworks

	Sea Basin Cross-Border Cost Sharing	Joint Regional Cost-sharing	Project-Specific Cross-Border Cost Allocation
What?	Estimation of costs and benefits for each European Sea Basin and indicative cost shares for Sea Basin countries	Joint cost negotiation process for a set of projectsamong North Sea countries, fed by technical input from TSOs, leading to a binding agreement	Binding decision by regulators to allocate costs among TSOs for a specific project
When?	Every 2 years	With TYNDP & national processes; frequency TBD	Ad Hoc
Legal basis?	Europeand TEN-E Regulation	Voluntary joint initiative	European TEN-E Regulation
Does?	• Full alignment with TYNDP and ONDP • Informative insights in costs & benefits for proposed ONDP infrastructure • Benefits for set of projects	• Benefits for set of projects • Involve partner countries early (i.e.: as of the planning stage) • Partner countries can steer assumptions	• Binding decision on cost sharing for a project • Formalized (administratively cumbersome) process • Requirement for EU funding
Does not?	• Provide binding cost-sharing agreements • Propose cost sharing for offshore generation	• Directly involve countries outside of the cooperation • Force cost sharing on countries which they did nog agree to	• Involve partner countries early (nor for steering of assumptions) • Lead to multilateral cost sharing in practice

Comparing cost-sharing methodologies

Methodological design aspects

The core principle of cost sharing for offshore infrastructure is that each country contributes in proportion to the benefits it receives. A given methodology will define how these benefits are assessed, and in turn, determine the cost-sharing keys which allocate project costs to partnering countries. Cost-sharing methodologies can differ along several dimensions, including whether benefits are assessed before or after final investment decision, whether benefits assessment is based on modelled predictions or observed metrics, the type of benefits considered, the scope of costs involved and the set of projects. The countries involved in a cost-sharing agreement will depend on the project set.

Framework definitions

To conceptually distinguish between methodological frameworks for cost and benefit assessment, we use the following definitions:

- Ex-ante: Prior to any Final Investment Decision on a project or project set subject to the cost-sharing agreement.
- Ex-post: After a Final Investment Decision has been taken on a project or project set subject to the cost-sharing agreement.

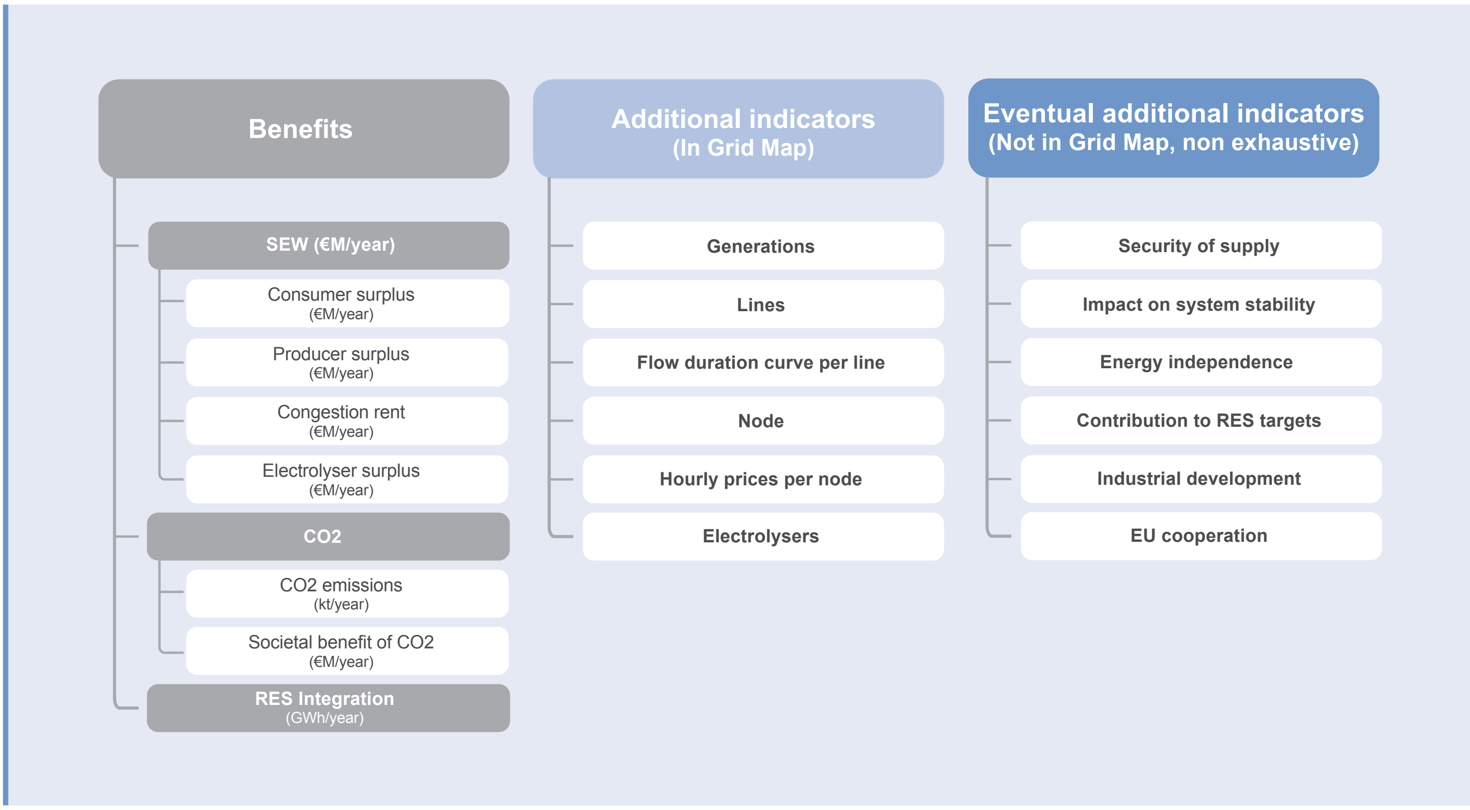
- Scenario-based: Benefits are estimated using one or more scenarios and sensitivities at sea basin level through a dedicated computational model.
- Observed metric-based: Benefits are estimated using measured or observed values, optionally applying a simple formula to combine multiple indicators.

Scope of benefits

Structuring a cost-sharing agreement entails choices regarding which benefits to include. Governments may seek to account for benefits such as e.g. including socio-economic welfare (SEW[8]), avoided emissions, renewable energy integration, security of supply, preparedness for unforeseen situations, less dependency from energy imports, and even industrial development (Figure 04).

Benefits can be assessed across all relevant system actors including producers, consumers and interconnector owners. The typical means of estimating benefit is through a scenario-based cost-benefit analysis.

Figure 04:
Potential benefits and indicators that could be included in a cost-sharing methodology

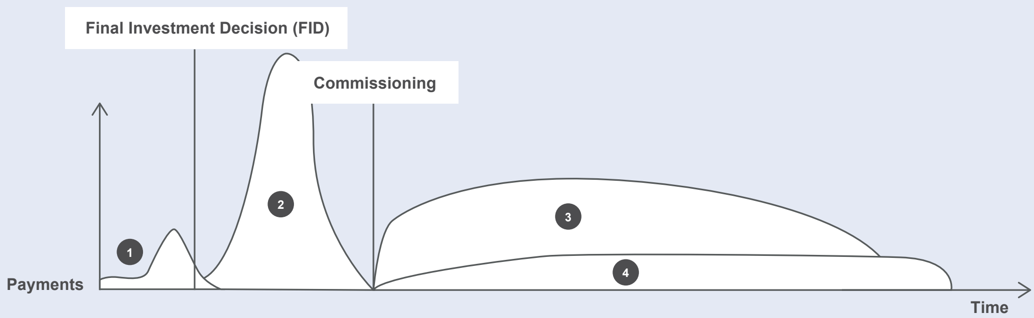


[8] Socio-economic welfare (SEW) is the sum of benefits gained by each actor in the modelling framework (producers, consumers, and transmission asset owners).

Scope of costs

Cost sharing among partner countries can in principle cover development expenditure (DEVEX), capital expenditure (CAPEX), and operational expenditure (OPEX) (Figure 05). While our methodology does not include DEVEX or OPEX, addressing how development costs and risks are shared is critical (Box 1). Decommissioning costs, incurred at the end of the asset's lifetime, will also be significant and merit early consideration in comprehensive cost-sharing frameworks.

Figure 05:
Illustrative offshore hybrid project cost components over time



	Cost type	Description	Consideration in cost sharing
1	Development Expenditures (DEVEX)	Preparatory expenses, such as studies, contractual arrangements prior to FID.	Typically borne by hosting countries, but seabedsurvey costs may be a barrier (see further)
2	Capital Expenditures (CAPEX)*	Costs for the construction and commissioning of the assets, such as purchasing cables, convertors, turbines.	Main focus of cost sharing.
3	Capital repayments (CAPEX + Cost of Capital)*	Financial costs associated to the capital required for the investment.	Main focus of cost sharing and financing.
4	Operational Expenditures (OPEX)	Maintenance costs (both fixed and variable) and operational costs after commissioning.	Only fixed Operation and Maintenance costs.Other OPEX costs are considered out of scope.

*onshore reinforcements are not considered in scope of the CAPEX cost sharing at this stage.

Simplified Development Expenditure (DEVEX) Cost-Sharing]

The most significant component of DEVEX by far is seabed surveys. For large-scale offshore hybrid projects, survey costs can be substantial and in the order of tens of millions of euros. While such costs are only a fraction of the total cost spent on such hybrid projects (typically billions to tens of billions of euros), they are nevertheless significant, and without due consideration, could be an impediment to further project development. For example, countries may not wish to solely incur the full DEVEX costs for a hybrid project if there are expected to be multiple beneficiaries and there is not sufficient confidence that it will lead to a CAPEX cost-sharing agreement and a FID decision.

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To facilitate progress on the critical planning and development steps, a simple DEVEX cost-sharing scheme may be required prior to a full cost-sharing agreement on CAPEX. Non-hosting countries who are expected to benefit from the project set could financially contribute to further development, for example by sharing costs of seabed surveys. In return, hosting countries could commit, in collaboration with the other countries, to fulfilling essential deliverables throughout the advanced project development phase, such as conducting seabed studies, delivering a refined CBA analysis, a CAPEX assessment and a proposed ownership model.

While this paper concentrates on CAPEX cost allocation, we do not exclude the possibility of NSEC governments including DEVEX, OPEX, induced internal reinforcement costs or decommissioning costs within their cost-sharing agreements in the future.

Accurate CAPEX projections are essential for informed cost sharing. As costs evolve during development, e.g. from seabed surveys or updated TYNDP or ONDP data, basic cost-sharing principles should be agreed early to provide predictability, facilitate regulatory approvals, and limit sunk costs. Final binding agreements should be concluded close to the FID, with principles refined as new information emerges.

Geographical scope

The geographical scope could encompass OTC TSO member countries, currently mirroring NSEC members and cooperation partners: Norway, Denmark, Germany, the Netherlands, Belgium, Luxembourg, France, Ireland, and the United Kingdom. For a specific cost-sharing agreement on a given project set, the geographical scope will be the mutually agreeing countries within the region.

Scope of projects

Building on the regional planning approach, cost sharing for offshore projects coming out of the joint planning exercise could be agreed for a set of projects rather than individually. Both generation asterisk and transmission costs should be included to reflect their interdependent benefits and provide a transparent basis for negotiations between countries.

For generation assets, this would not mean sharing full investment costs. Instead, governments could jointly act as counterparties to a support scheme such as a CfD. All cost-sharing arrangements must comply with unbundling rules, requiring separate financing for generation and transmission to prevent cross-subsidisation.

Evaluation criteria

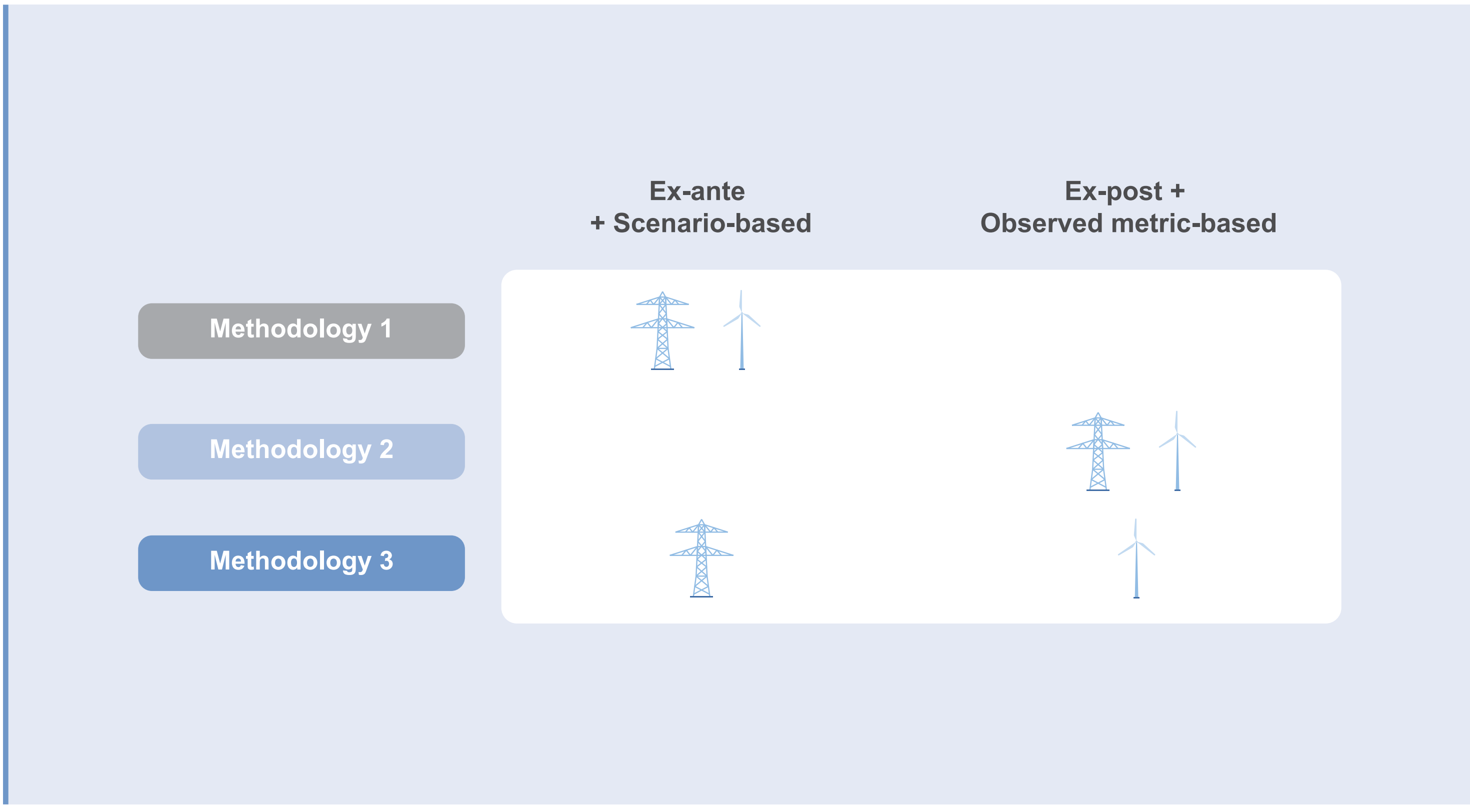
We assess cost-sharing methodologies against four criteria:

1. Predictability about the outcomes of a methodology, leading to a robust agreement on cost sharing, can increase stakeholder confidence, reduce investment risk and allow countries to adequately budget in advance.
2. Agility allows a cost-sharing methodology to adapt to a changing political and economic context but may reduce predictability.
3. Transparency regarding the underlying principles and assumptions that lead to the cost-sharing keys can enhance trust and support amongst cost-sharing parties and affected stakeholders.
4. Benefit reflectivity ensures that the costs allocated to partner countries are in proportion to the expected or realised benefits accruing to them from the project set. It must be clear for the parties involved that the cost-sharing outcome is better for them than without it.

Methodology options

In the following, we assess the ex-ante scenario-based framework and the ex-post observed metric-based framework for cost sharing, making use of the evaluation criteria described above. We also assess a potential mixed approach, applying an ex-ante benefit assessment to transmission and an ex-post approach to generation. Figure 06 categorises these methodologies according to the benefit assessment approach and the project type on this spectrum of the different methodologies. Finally, we explore further considerations on ex-ante and ex-post features that could complement the presented three methodologies.

Figure 06: Categorisation of the three assessed cost-sharing methodologies



Methodology 1: Ex-ante scenario-based for transmission and generation

Costs are allocated according to expected benefits provided by a project set. The benefits are determined by a modelling study based on predefined scenarios. To this end, parties to the cost-sharing agreement would agree on the modelling framework and collectively define the scenarios. The model could in principle produce any of the benefits covered in Section 3.2.1, based on the priorities of the parties to the agreement. The projection of how those benefits accrue to each country would serve as the basis for the cost-sharing keys.

Pros & cons

Cost allocation would be predictable for all parties and justified by the expected benefit. Contrary to observed metrics, modelling can reflect a significant range of benefits that can provide a representative vision of the societal value of the project sets across multiple countries. Furthermore, scenario-based cost allocation is the common practice for most infrastructure projects to date.

A key shortcoming of this approach is the uncertainty of outcomes, thus requiring parties to agree on assumptions and trust the model. Since such models are usually quite complex, this agreement and trust can be challenging to achieve. A robust stakeholder engagement process is therefore necessary. Lastly, it does not adapt the cost-sharing keys to real world results and therefore might not match the actual benefits received by the participating countries.

Methodology 2: Ex-post observed metric-based for transmission and generation

Costs are allocated based on observed, real-world metrics agreed by all parties involved, such as electricity imports and exports on the transmission assets[9]. The cost-sharing agreement would stipulate the time horizon over which these metrics are measured. A regular settlement schedule (e.g. annually) would be required to administer the dynamically evolving cost shares.

Pros & cons

Depending on the metrics chosen, ex-post settlement of costs based on observed metrics can reflect the evolving, real-world benefits received by each participating country. Provided data is publicly available, stakeholders could independently replicate the results. Ex-post cost sharing is inherently agile and responsive, as it is based on real-world observations.

[9] Alternatively, price-weighted import and export volumes could be considered to better approximate socio-economic welfare benefits over time.

The main drawback is that parties to the cost-sharing agreement will have uncertainty over the costs they will pay into the future. Any possible observable metrics are unpredictable and dependent on multiple variables which may not be in the hands of the participating countries. Lastly, it is not possible to directly measure every benefit using real-world metrics, limiting the possible options for representing the value provided by a project set.

Methodology 3: Ex-ante scenario-based for transmission and ex-post observed metric-based for generation

An ex-ante scenario-based approach (cf. methodology 1) could be applied to transmission infrastructure while an ex-post observed metric-based approach is applied to generation assets. For example, countries could agree that the power flows from the generation infrastructure to the hosting countries could be used as the metric to allocate the share of generation costs attributable to each country. The reason for distinguishing this specific mixed approach methodology is that CfD payments, the standard approach for financing wind generation, are inherently adjusted to the market ex-post during the lifetime of the asset, whereas this is not the common practice for infrastructure.

Pros & cons

For transmission, there are advantages in terms of predictability in costs for the funders of the infrastructure, but there are disadvantages with relying on a technical modelling assessment for determining cost-sharing keys that may not flexibly evolve with real-world conditions. For generation, the dynamic cost-sharing keys based on observed metrics could better reflect real benefits, but the uncertainty over the costs attributable to each country may create new risks for the cost-sharing parties.

We set out the cost-sharing methodologies and their associated advantages and disadvantages in Table 01. The numbers in parentheses represent the evaluation criteria. The evaluation criteria are predictability (1), agility (2), transparency (3), and benefit reflectivity (4).

Table 01:
Advantages and disadvantages of cost-sharing methodologies

Methodology	Advantages	Disadvantages
1: Ex-ante scenario-based	• Fixed cost shares give predictability on expenses and allow countries to budget in a timely manner. (1) • Current and tried practice for infrastructure financing. (3) • Model can estimate an extensive list of benefits. (4)	• Limited adaptation to correspond with realised benefits. (2, 4) • Technical computation based on assumptions, hence complex to understand the results. (3)
2: Ex-post observed metric-based	• Annual settlement based on real-world metrics is transparent. (3) • Payments can reflect what is happening in the real electricity system. (2) • Payments based on the actual use of energy are a standard model in many other fields for pricing energy. (3)	• Size of annual payment would vary depending on the development of the metrics of the measured flows. (1) • Could increase financing costs if investors are not shielded against ex-post adjustments. (1)
3: Ex-ante scenario-based transmission, ex-post observed metric-based generation	• Fixed cost shares for transmission infrastructure give predictability on expenses and allows to budget in a timely manner. (1) • Current and tried practice for transmission infrastructure financing. (3) • Model can estimate an extensive list of benefits combined with realised benefits. (4) • Use of import/flow as a benefit metric for generations allows for cost-sharing of CfD payments. • Allows for governments' contributions to correspond with actual benefits. (2)	• Limited adaptation to correspond with real benefits for the cost sharing on transmission infrastructure. (2) • Less experience with CfD sharing. (3) • Possible regulatory hurdles.

To illustrate the differences between the methodologies presented in this Section 3.2, worked examples are presented in Annex C, in which each methodology is applied to a set of dummy projects across four fictitious countries bordering a shared sea basin.

Further ex-ante/ex-post considerations

Ex-ante or ex-post cost-sharing methodologies can be combined in various ways, beyond the approach presented above with methodology 3. Different combinations mostly present trade-offs between predictability, agility and benefit reflectivity. However, regardless of the choice, the following two principles are key for the projects to remain investable:

- The cost-sharing agreement must be firm: countries should make binding commitments to their ex-ante cost shares or explicitly accept in advance the conditions and rules that would trigger an ex-post adjustment.[10] In either case, there should be no scope for reopening cost shares or the methodology after FID.
- Investors should be shielded from variations through ex-post adjustments, meaning that the risk of changes in cost shares after FID should fall to a public entity (more on this in the Financing section).

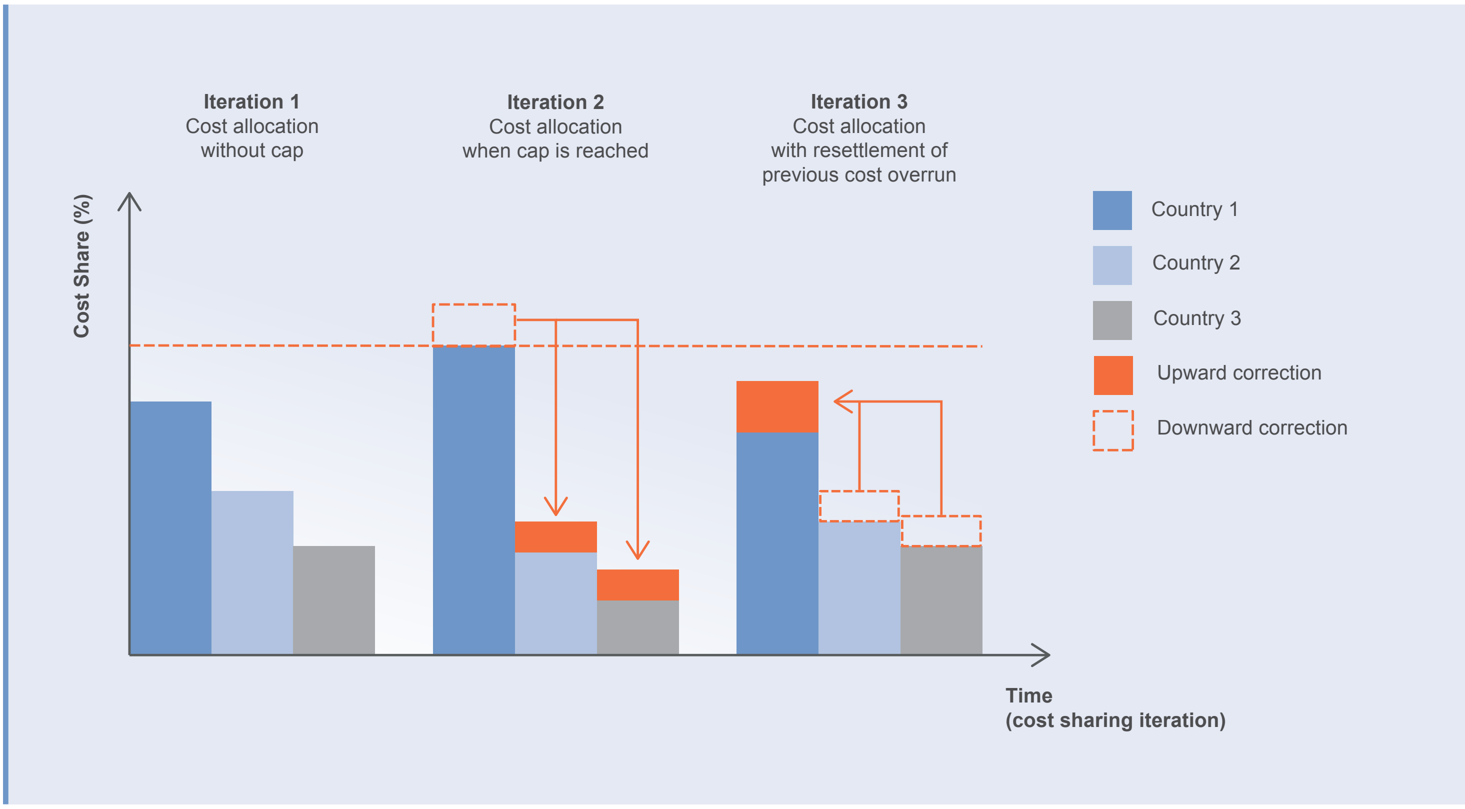
A first combined feature could be to recalculate the scenario-based indicators after the FID and automatically recalibrate the cost shares based on the new results in an ex-post scenario-based methodology. This approach better reflects real historical evolutions than an ex-ante scenario-based methodology and relies somewhat less on projections. On the other hand, it continues to rely on shared assumptions, such as those underpinning counterfactual scenarios, which parties would still be required to agree upon. For this reason, it only has value if there is a very high degree of trust in the model and assumptions. Without such trust, the added value of a re-calculation is limited, because parties may still end up questioning the results in ex-post.

A second combined feature could apply an ex-ante cost-sharing methodology, the result of a scenario-based cost-benefit analysis, to a percentage of the total estimated project costs. The remaining percentage of the total costs could then be allocated to benefitting countries over time through annual settlements, based on real-world observed metrics. There is no obvious rationale to take a specific percentage of the costs in ex-ante vs. ex-post, but it could be used as a tool to limit the exposure of the full project CAPEX to variations coming out of ex-post revisions.

[10] It is possible for certain conditions to "trigger" a change in the way costs are allocated. However, also in that case, both the trigger and the resulting change in principle should be firmly specified in the cost-sharing agreement.

An alternative way of limiting ex-post variations more firmly would be to introduce a cap to the cost share (Figure 07). A cap causes cost shares to not be aligned with the agreed benefit indicators for a period, but it could at the same time manage cost contributions that are not feasible to bear for any one partner during a settlement period. Such a value could be determined by looking at an annuity of the total costs of the project set and assess the highest financial burden any one partner could bear.

Figure 07:
Cost cap mechanism for ex-post adjustment



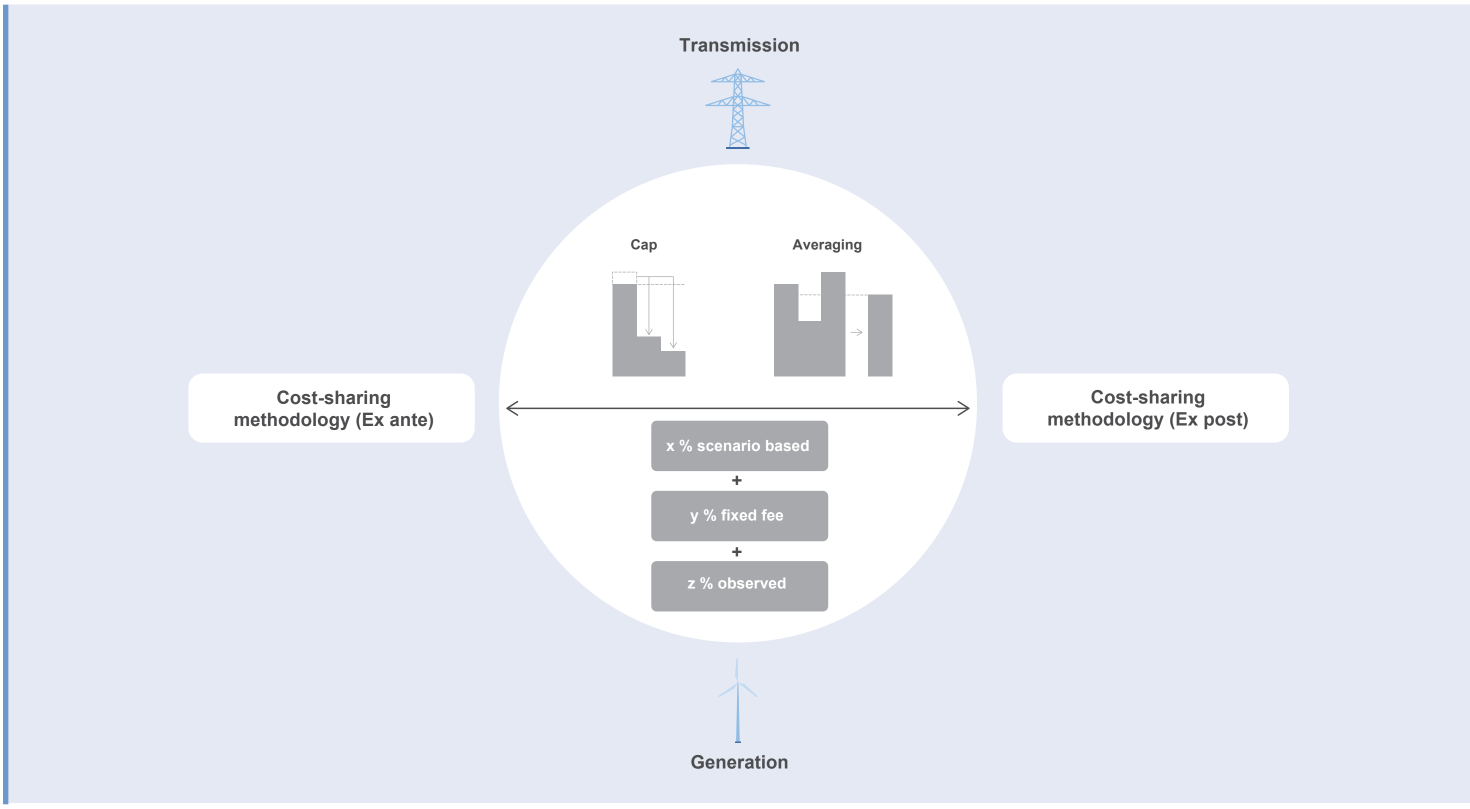
Reaching the cap at a given point in time would mean that some countries will be allocated a share exceeding their benefits (iteration 2 in Figure 07). This could be resettled at a later point in time when the ex-post process recalibrates the cost shares, via automatically including it in the new cost shares, or by introducing an additional compensation settlement at a later point in time (iteration 3 in Figure 07). This means that a country attaining the cap is not “off the hook” for paying that cost share but could defer payment of the full amount to a later date, to make the financial burden more manageable.

Another way to smooth the evolution of cost shares is to average the benefit indicators over larger periods of time. For import/export flows, for example, the cost-sharing methodology could look at a five-year rolling average. For scenario-based revisions, it could average the cost share over the past three assessments.

Lastly, there is also the possibility to share a part of the cost via a fixed fee. Such an approach could reflect the fact that any methodology is unable to reflect all benefits that come with new infrastructure projects, particularly those associated with public goods. A relevant example is security of supply. While methodologies exist to calculate security of supply[11], the real value of it considered by countries is difficult to assess. Its value depends on the kind of events countries want to protect themselves against, the likelihood of those events happening and the validity of the modelling approach to represent the impact of the events. If the event does not materialise, it will not be possible to assess the benefits ex-post. Some benefits may also not be attributable to any one country. An example is emissions‘ reductions, which benefit all countries regardless of where they are achieved. Such benefits which are hard to quantify and attribute could justify a fixed fee paid by all countries.

Figure 08:
Solution space for a combination of cost-sharing methodologies

There are many possible ways of combining ex-ante and ex-post cost-sharing elements into a mixed methodology (Figure 08). The methodology must be designed to allocate the risks of project development appropriately while ensuring that the needs of all stakeholders are addressed.



[11] ENTSO-E Guideline: ‘Guideline for Cost Benefit Analysis of Grid Development Projects (4th CBA Guideline).’ (2024).

IV. Financing offshore transmission assets

The OTC has engaged with multiple stakeholders (European Investment Bank [EIB], NSEC, European Commission) to gather the broadest and most accurate insights regarding the challenges and associated solutions for financing offshore transmission asset projects. These exchanges have also focused on the constraints of such solutions, including regulatory requirements or ownership limitations, as well as the importance of embedding a potential future financing solution within the regional exercise of joint planning and cost sharing.

Delivering interconnected offshore systems and energy islands in the North Seas requires substantial capital mobilisation. ENTSO-E's ONDP, published in 2024, indicated offshore grid investment needs of approximately 300 billion Euros by 2050 for the infrastructure required for an efficient connection of the targeted offshore wind generation capacities[12]. TSOs have several debt and equity financing options available to support offshore investments. However, crucially, TSOs differ in their ownership and financing structures as well as national regulatory frameworks. Some countries in the North Seas permit third-party development and ownership of interconnectors, while others apply regulatory restrictions that can limit such arrangements. These differences affect the suitability of specific financing options for offshore grid infrastructure and, specifically, for offshore hybrid projects. A toolbox of solutions will be required, rather than one specific financing mechanism for all projects within a sea basin.

Structural and regulatory factors affecting financing

Several factors may affect the appropriateness of one financing solution over another. To begin with, TSOs' ownership structures impact TSOs' ability to access certain forms of finance. In Europe, TSOs range from fully state-owned entities to publicly traded companies with mixed public-private shareholding. For example, state-owned TSOs may more easily access certain national public financing sources but can also have restrictions on their ability to collaborate with private investors. Conversely, privately owned TSOs may be more flexible in their approach but also be more reliant on volatile capital markets.

Differences in national regulatory regimes also shape the suitability of financing solutions for cross-border offshore electricity infrastructure. Specifically, permission to own offshore and operate cross-border transmission infrastructure varies by country. The UK, Belgium and Germany allow joint

[12] ENTSO-E: 'TYNDP 2024 Sea-Basin ONDP Report – TEN-E Offshore Priority Corridor: Northern Seas Offshore Grids.' (2024).

ownership by TSOs and external investors under strict conditions, while countries like Denmark, the Netherlands and France restrict ownership exclusively to national TSOs. Therefore, variations in ownership regulations across countries could create challenges for joint financing of offshore hybrid assets.

Additionally, there are inconsistencies in regulatory provisions for addressing external investor risks. Diverse approaches to cost recovery beyond national Exclusive Economic Zones (EEZs) potentially limit the viability of joint financing and equitable cost allocation of hybrid projects. Different interconnector revenue models across jurisdictions could also create risks for investors. Congestion income may decrease with more interconnection in the North Seas and therefore the distribution of congestion rents may be constrained. Furthermore, the use of congestion income to remunerate investors is limited by European regulation[13] yet the UK's regulatory regime endorses congestion income use through its cap-and-floor model.

The joint regional planning process proposed by the OTC and the outcomes of cost-sharing agreements also impact the optimal blend of financing solutions. For instance, as a cost-sharing agreement may define the amount and sequence of repayments to capital providers by participating countries and entities, the distribution of costs across borders may introduce "cross-border regulatory impacts" for investors, particularly if regulatory frameworks regarding cost recovery mechanisms differ significantly between jurisdictions. Therefore, cross-border cost sharing may require a separation of payment, ownership and risk management.

The structural and regulatory challenges described above and the relationship of financing with regional planning and cost sharing, implies that a flexible financing toolbox is required, encompassing an array of financing instruments, which can be adapted to the specific needs of individual projects or project sets and the partnering TSOs.

Financing solutions in the context of regional collaboration

Offshore financing principles

In the following, we define a set of principles for the financing toolbox which can account for the specific characteristics of offshore projects, including the scale of costs, the differences in TSOs' ownership and regulatory context, and the important interdependencies with planning and cost sharing.

[13] EU Regulation 2019/943, Article 19. Publication of the European Grids Package in December 2025 indicated that a percentage of congestion rent should be set aside for further investments into interconnection projects, however the eventual amount of congestion rent to be considered, if any, will be dependent on the final legal implementation of this proposal.

- **Reduce the cost of capital**

  The cost of capital is a dominant factor for overall project costs, especially for capital-intensive infrastructure such as offshore hybrid interconnectors. Even modest reductions in financing costs can deliver substantial savings. Therefore, financing solutions should enable TSOs and other project developers to access the least expensive capital available. This can be achieved by ensuring that financing structures are designed to reduce perceived risk, align with regulatory frameworks and accommodate a blend of public and private sources, if needed.

- **Leverage existing processes and funds**

  Wherever possible, financing solutions should build on existing financing processes and funding instruments, such as the Project of Common Interest (PCI) label/Project of Mutual Interest (PMI) label, the Connecting Europe Facility for Energy (CEF), the EIB's offshore energy investment strategies, the Marguerite Fund and relevant national programmes that could be extended to regional level. The OTC financing toolbox is intended to complement these established mechanisms. Leveraging existing frameworks can accelerate implementation, reduce administrative burden, and ensure alignment with broader EU energy and climate goals. To achieve this and set the needed incentives, alignment with national regulatory frameworks is a prerequisite.

- **Allocate risk appropriately**

  Offshore hybrid projects involve many risks, including, but not limited to, regulatory uncertainty amplified by the cross-border nature of offshore projects, construction delays, cost overruns, innovative technology, and transmission operation and maintenance challenges. Effective financing solutions should seek to allocate each type of risk to the entity best equipped to manage it. Financing instruments should also be flexible enough to account for evolving risks throughout the lifecycle of the project. By distributing risks appropriately, overall project risk can be reduced, improving bankability and increasing access to affordable financing. The regulated revenues for TSOs must adequately reflect the costs and risks.

- **Account for differences in regulation, ownership and project characteristics**

  Solutions within the financing toolbox must account for the significant differences in regulatory frameworks across the sea basin countries. A single financial structure, such as a project finance approach, cannot be universally applied, as some jurisdictions restrict the type of entities which can own, invest in, or operate offshore transmission infrastructure. National regulation may also foresee a certain financial structure and gearing limits. Further, project-specific financing can lead to cost increases in some cases, as complex financing structures can dilute accountability and increase contractual complexity. Beyond regulatory considerations, individual TSOs may have specific constraints.

For example, highly leveraged TSOs may face limitations in taking on additional debt, making off-balance sheet financing via project financing more suitable in some cases. Conversely, some TSOs may have specific advantages, such as access to state-backed low-interest loans or favourable credit ratings, enabling them to secure financing at relatively low costs. Additionally, each project will have unique characteristics that determine the optimal financing solution, including scale, technical design and participating countries. The financing toolbox should offer sufficient flexibility to account for these regulatory, TSO and project-level differences.

Catalyse private capital

In cases where substantial inflows of private capital are necessary, financing solutions should aim to strategically use public funding to unlock further investment from private sources, provided such private capital is affordable and aligned with project objectives. Thus, public funding should be targeted to reduce the cost of capital and increase the options and the scope for participation of private capital within appropriate structures.

Table 02:
Opportunities and challenges with debt and equity for financing offshore hybrid infrastructure

Offshore financing toolbox

TSOs have a range of financing tools that can mobilise capital for developing offshore hybrid projects. Firstly, the broad mechanisms of debt or equity present distinct opportunities and challenges, set out in Table 02.

Financing type	Opportunities	Challenges
Debt Secured through loans from public financial institutions, such as national development banks or the EIB, commercial banks or capital markets, for example via green bond issuance.	• Fast means to access capital can support ambitious deployment targets. • Often cheapest financing mechanism, thereby reducing investment cost and ultimately benefitting consumers.	• Breaching leverage thresholds can affect TSOs' credit rating, increasing cost of capital. • Commercial banks have sectoral exposure limits beyond which no additional debt can be withdrawn.
Equity Sourced from financial markets, if suitable for a TSOs' ownership structure, or capital contributions can be received from shareholders, including from governments if the TSO is publicly owned.	• Raise capital without repayment pressure or credit risk. • Shareholders could offer longer-term support, providing stability. • Equity and equity-like instruments[14] could be used to tailor to the financing needs in which equity-like instruments can raise capital while reducing pressure on the credit rating.	• Dilution of control and decision-making could create development and operational difficulties in already-complex offshore hybrid projects. • Shareholders may want a higher return than lenders since they bear more risk. • Access constrained by differences in TSO ownership and offshore transmission ownership regulations.

[14] Equity-like instruments are flexible financing instruments that blend features of debt and equity, offering investors returns linked to company performance without granting full shareholder rights.

Table 03:
A non-exhaustive toolbox for financing offshore transmission assets

Within the categories of debt and equity, there are various financing tools which TSOs can use to raise capital. Some of these are already in application and could be disposed more strongly, while others are new and must be further developed. The tools are not mutually exclusive, and oftentimes, multiple tools are utilised at different stages of an offshore transmission project lifecycle. Table 03 provides a non-exhaustive list of financing tools which could be suitable for offshore transmission projects.

Financing tool	Description
Debt	
Bonds	Various types of bonds, including classic bonds, registered bonds, green bonds and ESG-linked[15] bonds, are already used successfully by some OTC TSOs and will remain one of the main funding sources for offshore transmission.
Promissory note	Promissory notes – a legally binding guarantee to make a payment on demand or at a future date – are used by some OTC TSOs, typically for small assignments by contractors.
Commercial bank loans	Commercial bank loans, and specifically green loans for projects that deliver environmental benefit, are a common tool for offshore transmission infrastructure. Access to such financing may become difficult as banks reach sectoral exposure limits. Financing consortia constituted by different commercial banks may become a more feasible arrangement for hybrid projects.
EIB-supported loans	The EIB provides long-term financing for projects that align with EU policy objectives. Clarification is needed on the scale of EIB loan support to assess the facility's effectiveness for hybrid projects. Possibility to increase European funding to consider hybrid offshore projects or other projects which have a similar innovation and risk profile.
Loans supported by national development banks	National development banks can provide long-term loans and credit enhancements aligned with national policy goals. Best practices on credit enhancements, such as low-rate offerings or catalysts to sponsorships, should be identified and learnings applied to offshore hybrid project sets.
Export Credit Agency (ECA) backed financing	A specific form of guarantee-eligible contracts involving goods that cross borders and/or are produced in foreign countries.
Guarantees	

[15] Concerns bonds which are linked to defined "environmental, social, governance"-standards.

Loans with guarantees through InvestEU	InvestEU loans with guarantees can de-risk offshore transmission financing, thereby reducing the cost of capital and attracting private investment.
Guarantees through EIB or Member States	Institutional credit support can de-risk offshore transmission projects and enable long-term financing. EIB support should be extended in the MFF from 2028 onwards and hurdles for Member States in the context of State Aid should be minimised.
Equity-like instruments	
Mezzanine financing	Mezzanine financing in offshore infrastructure projects is a hybrid funding solution that sits between senior debt and equity, providing developers with additional capital without diluting ownership.
Grants	
Connecting Europe Facility (CEF) for Energy	CEF-E grants can be awarded to PCI- or PMI-labelled projects. As defined by the TEN-E regulation[16], a CBCA exercise (see Section 3.1) is a prerequisite for CEF-E funding. This requirement should be removed to facilitate CEF funding for project sets that use alternative cost-sharing approaches.
National government grants	Governments may choose to provide grants for projects which meet national policy goals. Importantly, public funding should not downgrade the attractiveness of the projects or lower the rate-of-return, as the risk profile for the projects remains unchanged.

Offshore financing structures

Financing tools can be utilised within various financing structures. The choice of tools and structures can determine how well the overall financing solution adheres to the principles set out in Section 4.2.1. National legal and regulatory frameworks are decisive in terms of making the financing and organisational structures possible. A visualisation of different financing structures can be found in Annex D.

Corporate financing

Corporate financing for offshore transmission infrastructure involves regulated TSOs raising debt and equity directly on their balance sheets. All project risks remain with the TSO, as the terminology is not typical as well as costs and revenue. Corporate financing has the advantage of being widely known and applied as the traditional means for financing TSOs’ investments, with legal certainty and potential for rapid deployment.

[16] Regulation (EU) 2022/869, Art. 16.

Equity investors are involved via participation in corporate equity, and the debt capital can also be directed to a project via contractual agreements.

However, additional debt may place undesirable strain on TSO's balance sheets and affect their credit ratings. Given the likelihood of equity and debt constraints when investing in projects with large CAPEX volume, consolidating project debt in all cases could reduce the flexibility for other TSO investments, for example in national grid reinforcement. This could be especially the case for TSOs with mainly privately financing sources and companies with a low asset base. In the case of cooperation projects, the collaborating TSOs can establish a wholly owned Special Purpose Vehicle (SPV) that holds the project assets. However, the SPV is consolidated, and the debt ultimately remains the responsibillity of the parent TSOs.

Project financing

Project financing means a financing of investments solely based on the cash flows rather than the balance sheets of its sponsors, also referred to as off-balance sheet or non-recourse financing. Project finance can mobilise additional capital for offshore projects by creating financing structures that attract different sorts of capital. Project financing is widely used in infrastructure investments, e.g. renewable energy projects. SPVs are used to legally structure the investments and ringfence project risks, which comes with certain transaction costs while implementing and managing the SPV.

As lenders can rely on project cash flows, the costs of capital could tend to be higher in comparison to corporate financing via TSOs with a high asset base and certain revenues. However, leverage of financial structure is possible, and external capital may be included more easily. The latter also depends on regulatory frameworks. Many jurisdictions require TSO ownership of offshore transmission assets, limiting the feasibility of applying an SPV structure and project financing to their development. Specific regulation on compliance with unbundling rules applies and, in some jurisdictions, the SPV must be certified by the regulatory authority. Furthermore, investor priorities may conflict with the goals of efficient system planning and optimal operation of the transmission assets.

Innovative financing structures

To account for ownership, financing and regulatory differences between TSOs, more innovative financing structures may be required. A "double SPV" financing approach, as coined in Elia Group's White Paper[17], would see the TSOs retain control of the project development, ownership and operation through an Owning and Operating Special Purpose Vehicle (O&O SPV).
A separate Financing SPV would raise capital from external investors, backed by the revenue assigned to it via a contractual agreement with the O&O SPV. The Financing SPV would have no direct recourse to the TSOs.

[17] Elia Group (2025), Financing Offshore Interconnectors across the North Sea.

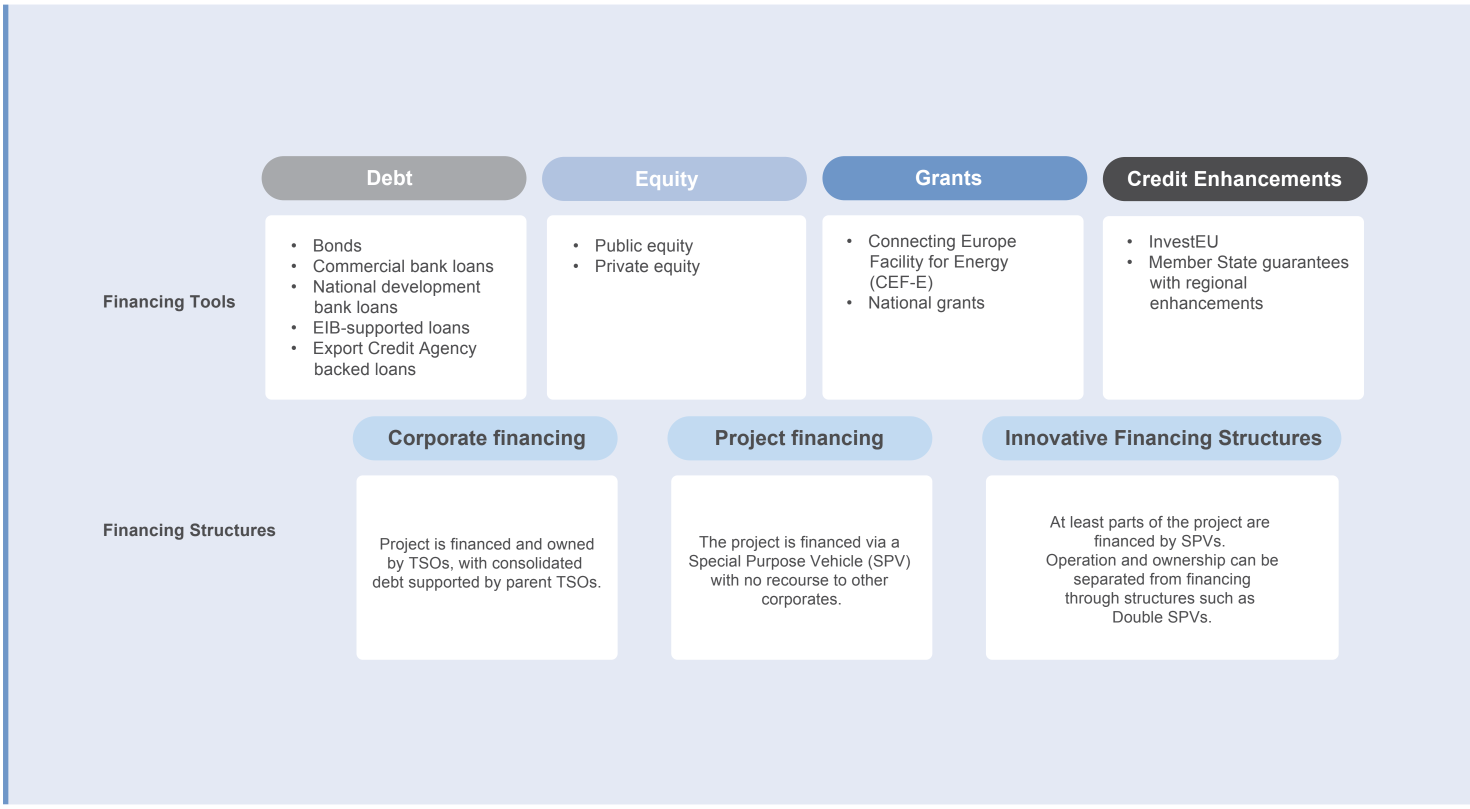
Table 04:
Financing tools and financing structures

Financing structure	Advantages	Disadvantages
Project financing	• **Mobilise additional capital** by attracting new investors through suitable financing structures.	• **Ownership barriers:** Many jurisdictions require TSO ownership, limiting its feasibility. • **Governance issues:** Complex frameworks dilute accountability and lead to slow decisions. • **Operational misalignment:** Investor priorities may conflict with system optimisation.
Corporate financing	• **Ample experience** (traditional way of financing TSO investments). • **Legal certainty.** • **Rapid deployment.**	• **Increases strain on TSO credit metrics and ratings,** as equity and debt headroom may become limited in the long run. • Consolidation of project debt **reduces flexibility for other TSO investments.**
Innovative financing structures (i.e. Double SPV approach assessment)	• **Preserves TSO control** and enhances compliance with national regulatory requirements. • **Mobilises private capital** at scale. • **Creates conditions for partial debt deconsolidation.** • **Reduces reliance on scarce public funding,** while keeping financing costs affordable. • Provides a more pragmatic balance between traditional TSO models and private-sector project finance ones.	• **Ownership barriers:** Many jurisdictions require restrictive TSO ownership and operation on the national territory, constraining its feasibility. • **Higher complexity** in terms of contractual agreements, regulatory framework and, thus, transaction costs. • **Risk of higher overall financing cost:** depending on ability to de-risk the proposed investments to make them suitable for private instruments. • **Liquidity risk / attractiveness to private investors:** features must align with investor expectations in terms of structure, returns and risk allocation. • **Consolidation risk:** Financing and Revenue Allocation Agreements must be sufficiently robust to isolate the SPV's debt obligations from the TSO's own liabilities.

Financing structure: takeaways

While the financial structure of hybrid offshore transmission projects may have an impact on the availability and costs of capital, it has less impact on the general setup of these projects. Specifically, the involved project partners and suppliers, as well as the regulatory framework and network codes, remain the same, while project sponsors and investors could deviate. Thus, the use of project financing does not mean that CAPEX or OPEX are reduced. However, well-designed financing structures can have a positive effect on the cost of the financing itself. Therefore, the use of corporate or project financing strongly depends on the regulatory framework and the individual financial and ownership situation of a TSO. Figure 09 provides an overview of the financing tools and structures proposed above.

Figure 09:
Financing tools and financing structures



Financing of offshore projects considering cost sharing and ownership

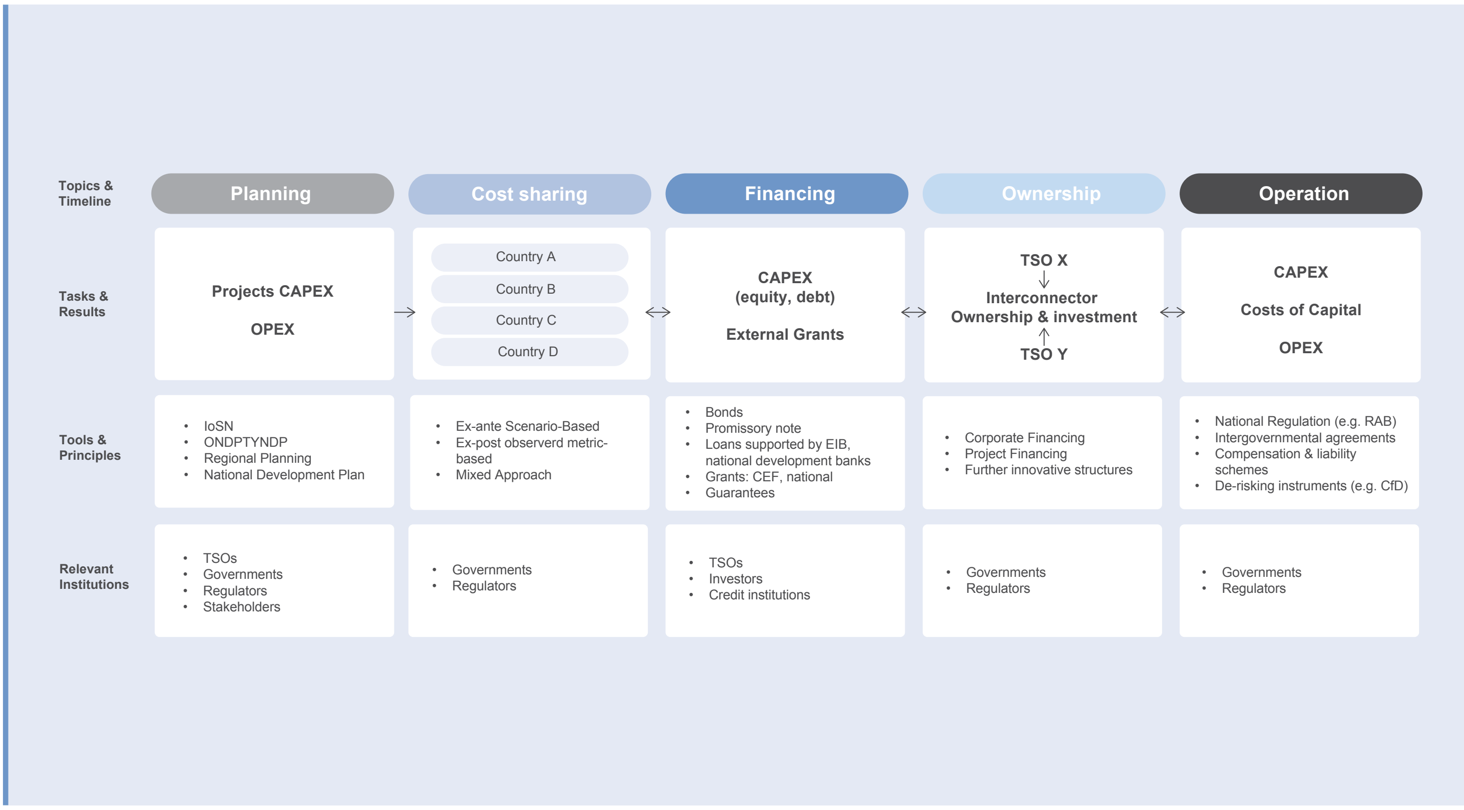
As clarified in the previous paragraphs, a flexible financial toolbox is essential to address the regulatory and ownership diversity among TSOs. This adaptability ensures that financing solutions can meet the specific requirements of each context. At the same time, the financing of offshore projects is influenced by various factors such as planning, cost sharing and regulatory frameworks. Real-world examples of interconnector financing are discussed in Annex B.

Cost-sharing arrangements significantly impact the structure of financing. When costs are allocated ex-ante, investors have clarity on the needed amount of funding and financing. This reduces uncertainty for investors and, thus, reduces the cost of capital. In contrast, ex-post adjustments can create unpredictability in terms of amounts to be financed and could raise capital costs. To mitigate these risks, investments should be protected from ex-post changes, for example through national or international regulatory frameworks that use instruments such as levies as a possible mechanism to manage evolving costs and transfer ex-post adjustments between countries. Such an approach entails that the uncertainties related to the ex-post cost share changes are observed by governments and are also agreed with national regulators, as "cost-sharing settlement levies" will impact the costs and benefits of final consumers in a different way than with ex-ante settlements.

Regulatory frameworks also shape financing and funding strategies. Project revenues depend on the applicable regulatory regime. As stated in the previous section, cross-border cost-sharing agreements may imply a separation of investment amount and ownership of the project partners. If so, this would require regulatory and legal solutions to accommodate such an approach as national regulatory authorities must approve the revenues based on the invested assets. Otherwise, other entities than TSOs, most likely governments, might have to step in to resolve the discrepancies between the cost shares and the investment on one hand and the ownership shares on the other hand. A key question also is whether all investments will be reimbursed via national tariffs through mechanisms such as the Regulatory Asset Base (RAB) or Cap and Floor (C&F) models. These elements together have an impact on investor confidence and as such the costs of capital. Additionally, the regulatory framework also applies to liabilities and compensations for market parties like offshore wind farms and from the regulator towards the TSOs.

Finally, a cost-sharing agreement will reflect to a certain extent the distribution of benefits between countries regardless of whether it is the result of an ex-ante or an ex-post methodology. Where costs and benefits between countries vary significantly, the gap between investment amount and ownership may be too high to be paid by a country or its end consumers. In this case, to realise the project, the investment may need to be complemented by grants, such as the Connecting Europe Facility (CEF). The interdependencies of financing with cost sharing, ownership and regulation are summarised in Figure 10.

Figure 10:
Interdependencies on financing of hybrid interconnectors considering cost sharing, ownership and regulation



V. Next steps for 2026

The OTC now looks forward to turning the joint planning work into a recurring and structured exercise – starting with the next OTC planning process cycle in 2026. The 2026 planning cycle will continue and strengthen the work on identifying cost-effective sets of projects in the North Seas that deliver regional benefit. All relevant stakeholders will be onboarded in the process from the start: governments and national regulatory authorities, as ultimate decision-making bodies, third-party project promoters, hydrogen TSOs, wind farm developers and civil society. This early engagement is essential to ensure full transparency on key parameters of the analysis and buy-in from decision makers, in particular in context of cost and benefit sharing. Information and data provided in the future planning cycles will support the continued investigation of cost sharing and financing.

Our expert paper provides a first overview and assessment of cost sharing, yet the optimal cost-sharing methodology is the one that leads to an agreement between partner countries to finance and deliver projects emerging from the regional planning. The decision should be taken by the governments of the relevant North Sea countries, in coordination with their NRAs, and thus the OTC calls for a structured dialogue with these parties on the subject of cost-sharing. Concretely, the next planning cycle requires an agreement early in 2026 on which cost and benefit indicators should be delivered, as well as the high-level principles for the envisaged methodology, to ensure that the study meets the needs for regional cost sharing.

Based on the OTC's technical assessment presented in Section 3 and engagement with critical stakeholders, the OTC recommends that a cost-sharing approach which combines ex-ante scenario-based and ex-post observed metric-based elements is further developed as a candidate methodology for application to project sets. Such a combination can balance the predictability of ex-ante determined cost shares with the agility and accuracy of ex-post cost shares adjusted based on real-world observed metrics. To enrich the basis of discussion for decision makers, the OTC will develop the ex-post methodology to illustrate its application, also in combination with the ex-ante methodology.

The engagement process should continue to be able to deliver a detailed and binding cost-sharing agreement around the time of the delivery of the CBA assessment of the joint regional planning (planned for 2027, cf. OTC Cooperation Paper). In parallel, even the most advanced projects considered in the Grid Map require further development before an FID is possible and should be realised to ensure the timely implementation of a first set of projects. Typically, this action falls to the hosting TSOs for the concerned projects, but in the context of this cooperation, the OTC recommends partner countries discuss how they can support the development of projects in the region, potentially through a simple sharing of the financial burden of the advanced development stage.

Once there is a joint commitment on which projects to build and how to allocate the costs, the parties concerned will face the challenge of attracting capital for these investments. As TSOs differ in their ownership and financing structures and must adhere to different national regulatory frameworks affecting the suitability of specific financing options, the OTC recommends that a flexible financing toolbox is developed, which can meet the needs of the respective TSOs and projects. The financing toolbox can encompass various debt and equity instruments that can be organised into corporate finance, project finance or innovative structures. Solutions within the financing toolbox should adhere to the principles set out in Section 4.2.1.

To ensure a robust financing framework for offshore interconnector and hybrid projects identified in the regional planning exercise will be in place, the following actions are key:

- **Clarity on cost-sharing agreements and principles** is needed. While some elements on financing can be addressed independently, the cost-sharing outcome and principles should take the concerns of potential investors into account to minimise investor uncertainty and thereby reduce the cost of capital.
- **The regulatory and legal frameworks** must be further studied and developed. The existence of potential gaps between investment shares and ownership structures should be legally treated and revenue approval and liability management must be decided.
- **Complementary funding mechanisms** such as grants from programs like the Connecting Europe Facility (CEF) should be explored to see whether they can partially bridge financial gaps in cases where there is an unbalanced distribution of costs and benefits between countries or where strategic European goals can be achieved.
- **Flexible financing tools** should be designed, tailored to offshore grid development and enabling TSOs to secure capital efficiently. They should address the unique aspects and timelines of offshore projects while helping to resolve the strain on TSOs' balance sheets.
- **Alternative financial structuring options** that can help attract a variety of financing sources while acknowledging the essential role TSOs play in developing and operating offshore grids should be assessed.

OTC’s 2026 objectives

In 2026, the OTC will focus on turning the political ambition of the NSEC into tangible progress on offshore grid development in the North Seas. A key priority will be to support respective governments to establish robust and practical cost-sharing frameworks that align with a joint regional planning approach. These frameworks will give project promoters and regulators the clarity needed to move concrete offshore projects toward final investment decisions and, ultimately, construction.

The OTC will also further develop the TSO perspective on financing challenges and identify workable solutions capable of supporting the scale of Europe’s offshore energy ambitions. As part of this, the OTC will shape a coordinated and actionable process involving governments, national regulatory authorities, TSOs, and other key stakeholders. This integrated process is intended to align planning, cost sharing, and financing from the outset, enabling more efficient project development.

Building on the jointly identified “promising projects” in the offshore Grid Map, OTC will work together with key stakeholders, including NSEC governments and NRAs, to help advancing these projects toward concrete cost-sharing agreements. This will unlock the next generation of offshore assets and bring them significantly closer to realisation, financing, and operation. Through these efforts, OTC will help realise political ambitions and implement offshore infrastructure across the North Seas region.

VI. Annexes

Annex A: Project list

Border	Description
IE-GB	• Further links between Ireland and Great Britain are considered. Mares and LirIC have both obtained (in principle) cap and floor regimes from Ofgem and have been factored into the study's background. • An additional multi-purpose interconnector connecting the potential offshore wind leasing areas in each respective country's EEZ has been found to be beneficial. The viability of such links would be subject to the respective offshore leasing activities of each country. • Such a multi-purpose interconnector could facilitate wind off the south coast of Ireland in an area recently legislated for offshore development and, if technically feasible, could be targeted for delivery in the late 2030s.
IE-FR	• Recent and ongoing studies, including the OTC Grid Map study and the ONDP, support increased capacity. However, grid reinforcement is a prerequisite for further interconnector developments in France. EirGrid and RTE are initiating more detailed market studies to assess a hybrid interconnector which would stretch from the south coast of Ireland to northwestern France. • The project aligns with the Irish Government's policy statement on interconnection and could connect offshore wind in both the Irish and French EEZs. This includes wind that would be located in an area of the Celtic Sea which the Irish government has recently legislated for in offshore development. • If technically feasible and economically viable, this project would be targeted for delivery after 2040, once the French internal grid has been reinforced. • No project is currently included in the French draft National Development Plan (NDP).
FR-GB	• Multiple projects, including non-regulated projects, still need to undergo a political agreement between the French and British governments and NRAs. • Our study found that 1 GW of additional interconnection capacity between Britain and France added value.

FR-GB	• The study CRE published on the value of new interconnection capacity between the two countries found that under certain conditions, a capacity of around 1 GW of new interconnection could be beneficial for France. CRE's analysis highlighted that the benefits for France were insufficient compared to the costs of a new project if the costs and revenues were shared equally between the UK and France. In CREs view, only a redistribution of costs between the two countries was likely to be considered acceptable for projects to proceed. A joint statement has been made by CRE/Ofgem on the next steps to achieve 'around 1 GW' of new interconnection. • No project is currently included in the French draft NDP.
BE-GB	• Nautilus – the hybrid system between GB and the Princess Elisabeth Island – is depicted on the Grid Map as an ongoing project. It is to be noted that future governmental decisions on the project and regarding the scope of the Princess Elisabeth Island could have different potential implications, in particular on Nautilus, that will be considered in upcoming versions of the map. • Like in the ONDP, an additional level of interconnection over and above the already planned Nautilus project has been identified as being beneficial within the study. • This assumes additional offshore wind leasing on the east coast of Great Britain which would then be connected to the Belgian mainland. • Future offshore wind capacity will be subject to the recommendations of the Strategic Spatial Energy Plan and leasing decisions of The Crown Estate, and The Crown Estate Scotland.
GB-NL	• For LionLink, the development phase started in 2023. The interconnector should be operational in 2032. • Furthermore, a new promising interconnector candidate has been identified. This assumes additional offshore wind leasing on the east coast of Great Britain which would then be connected to the Dutch offshore wind area. • For the UK future offshore wind capacity will be subject to the recommendations of the Strategic Spatial Energy Plan and leasing decisions of The Crown Estate, and The Crown Estate Scotland.

DE-GB	• The map shows four projects between Germany and the UK. Two point-to-point interconnectors are categorised as planned projects, NeuConnect and Tarchon (each 1.4 GW). Moreover, TYNDP 2024 has already identified the benefit of a 2 GW hybrid project between the two countries, which received PMI status in December 2025. • In addition to that, several studies have identified the potential for a further hybrid interconnector project (2 GW). Our study has also found that establishing an additional hybrid interconnector between the two countries could provide significant economic benefits. Consequently, the 3 German TSOs submitted a respective project to TYNDP 2026. • This assumes additional offshore wind leasing on the East coast of Great Britain which would then be connected to Germany. Future offshore wind capacity will be subject to the recommendations of the Strategic Spatial Energy Plan and leasing decisions of The Crown Estate, and The Crown Estate Scotland.
DK-GB	• Studies continue to show potential for a link between Denmark and Great Britain. • Concrete project development remains at an early stage and needs further investigation.
NO-BE, -DE, -DK, -UK, -NL	• There could be a capacity for up to two hybrid interconnectors, with a potential for up to 2800 MW HVDC connections with Norway. The first OTC Grid Map study and/or other studies on system level have indicated that up to two hybrid interconnectors could be beneficial within 2040 timescales. See Statnett report 'Grid concepts Sørvest F – An analytical basis for determination of grid concepts for bottom fixed offshore wind in Sørvest F' (2025). • Statnett (NO) has signed MoUs with Amprion (DE), Elia (BE), Energinet (DK), National Grid (UK), TenneT (NL) and TenneT (DE) respectively. Grid topologies and technical and market issues related to possible hybrid interconnectors have been investigated.
BE-DK	• TritonLink continues to show benefits for EU • Further project development relies on agreed cost-sharing and funding framework.

BE-NL	• An MoU was signed on 24 April 2023 between Elia (Belgium) and TenneT (Netherlands) that covered a study of electricity interconnector options that would link Belgium to the Netherlands. • A joint task force has been launched, and grid studies have been undertaken throughout 2024 and 2025 to, amongst other things, investigate the potential socio-economic benefits of multipurpose or hybrid interconnectors. This project is part of the TYNDP but not part of the identified topology.
DE-NL	• A hybrid interconnector between the two countries is being discussed at ministerial level and further investigations are ongoing. The benefit and cost negotiations have not yet started. • TenneT supports both ministries in their ongoing discussions regarding the technical design and integration into the North Sea development and energy infrastructure planning process.
DE-DK	• The first North Sea hybrid interconnector between the two countries is being discussed at TSO and ministerial level, and an agreement has been reached on the project topology. The agreed topology foresees integrating 4 GW of offshore wind in the Danish EEZ via two HVDC connections (one to Denmark and one to Germany) and enabling additional cross-border trade capacity. • The technical design is being developed as part of an ongoing cooperation between Amprion and Energinet. Feasibility and regulatory preparations are ongoing, with commissioning targeted for the late 2030s to early 2040s, subject to permitting, wind deployment, and supply-chain developments. • In addition to the first hybrid interconnector, there is potential for further hybrid projects or cross-border radial lines between Germany and Denmark. The latter would allow wind farms in the Danish EEZ to be exclusively connected to the German mainland.

Annex B: Real-world examples of innovative financing solutions

Important learnings can be gathered from the application of financing solutions to real-world cross-border offshore transmission projects.

The Biscay Gulf interconnector, a 2 GW project between Spain and France, received € 578 million grant from the CEF-E programme. The project is a joint venture between the respective TSOs, Red Eléctrica (Spain) and RTE (France), and involves separate loans to each entity without any joint financing mechanism. European funding was critical for the project's success as it was required to ensure at least a neutral NPV for all parties.

The Celtic interconnector between Ireland and France also received substantial support of € 530 million from the CEF-E fund. A joint venture between EirGrid (Ireland) and RTE (France) was established and a regulatory framework for project revenues was defined by the respective regulators. EirGrid's position as an asset-light company affected the availability of certain forms of debt for the project.

NeuConnect interconnector between the UK and Germany, via the Dutch EEZ, is an example of an offshore project using a non-recourse project finance structure. The project is 100% backed by private equity through a consortium of over 20 financial institutions. To accommodate different regulatory regimes, three borrowing entities were established, with the debt sized according to the regulated revenues in the respective jurisdictions. The regulatory framework combines a cap-and-floor model in the UK context and a RAB model in Germany.

The examples demonstrate the importance of adapting financing structures to the specific needs of the TSOs, regulatory regimes and projects or project sets. Due to the differences in ownership and regulation, a single, predesigned financing solution would not have been possible to use across all the above cases. Furthermore, the importance of a suitable regulatory framework for ensuring sufficient and predictable project returns is also well illustrated. Stable returns are a precondition for attracting investment and minimising the cost of capital, thereby supporting the goal of an efficient development of the North Seas offshore grid.

Annex C: Cost-sharing examples

This Annex illustrates the differences between the methodologies presented in Section 3.2. Each methodology is applied to a set of dummy projects across four fictitious countries bordering a shared sea basin. The examples are purely illustrative and do not derive from any real data or project. They serve only to demonstrate how the methodologies function in practice.

Dummy North Sea

Four countries (Zones A–D) jointly develop five offshore hybrid projects providing overall positive socio-economic welfare. Their energy profiles are as follows:

- Zone A: Renewable-heavy system, phasing out coal and nuclear, increasingly reliant on imports.
- Zone B: Nuclear, wind and solar mix, remaining net importer.
- Zone C: Large wind and solar base, minimal fossil fuels, growing net exporter.
- Zone D: Expanding renewables, declining domestic fossil output, current import dependency.

The project set includes offshore wind farms and hybrid interconnectors across the four zones, as illustrated in Figure 11. Total investment assumptions for generation and transmission are also shown (€ 18 billion for the transmission part, € 14 billion for the generation part, € 32 billion in total). For the sake of simplicity the costs share for the generation is considered as a real cost share, while in Section 3.2 it is clarified that it should be considered as a the share for which the party becomes a joint counterpart of the CfD support scheme.

Figure 11:
"Dummy North Sea" countries collaborating on developing an offshore hybrid project set

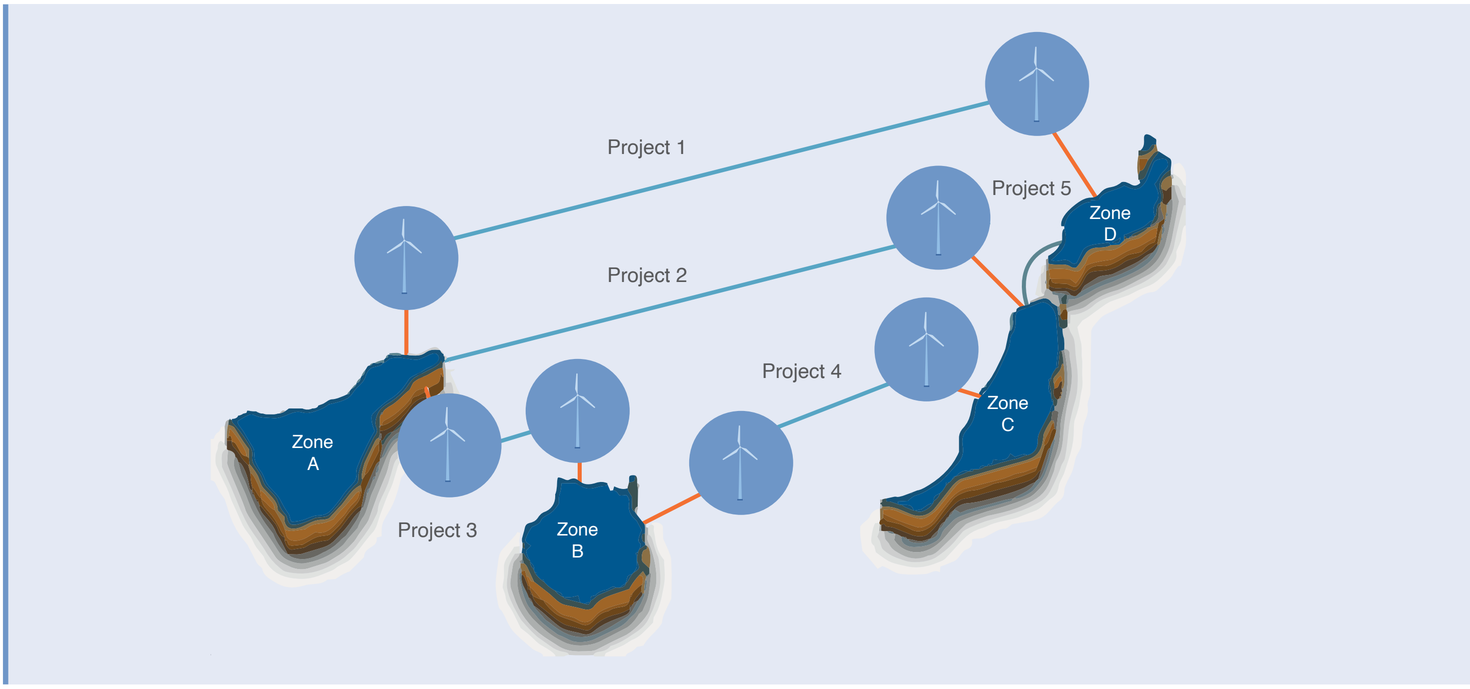


Table 05:
Methodology 1 cost-sharing example

Methodology 1: Ex-ante scenario-based for transmission and generation

Costs are allocated ex-ante using a scenario-based model assessing SEW benefits. Illustrative results are presented in Table 05.

Zone	SEW	Cost sharing ratio	Cost (€ million)
A	17,000	50%	16,000
B	7,500	22%	7,059
C	5,000	15%	4,706
D	4,500	13%	4,235
Total	34,000	-	32,000

The cost-sharing results are based on scenario-driven modelling of SEW benefits at the FID stage. Each country's contribution reflects its share of total SEW gains from the project set. Zone A, which receives the largest welfare benefit, contributes the most (€ 16 billion), while Zones B–D pay smaller amounts in line with their lower benefits.

Methodology 2: Ex-post observed metric-based for transmission and generation

The ex-post observed metric-based methodology determines cost-sharing ratios after project completion, using real-world operational data. In this example, the chosen metric is each country's annual electricity imports across the hybrid interconnectors (Table 06).

Table 06:
Methodology 2 cost-sharing example

Ex-ante scenario-based import projections				Ex-post observed actual imports			
Zone	**Projected Imports (GWh)**	**Cost sharing ratio**	**Cost (€ million)**	**Observed Imports (GWh)**	**Cost sharing ratio**	**Final ex-post Cost (€ million)**	**Annual Correction (€ million/year)***
A	32,500	50%	16,000	24,050	37%	11,765	169
B	14,300	22%	7,040	16,250	25%	8,000	-37
C	9,750	15%	4,800	16,900	26%	8,471	-151
D	8,450	13%	4,160	7,800	12%	3,765	19
Total	65,000	-	32,000	65,000	-	32,000	-

*Annual correction is an average payback over an estimated 25-year period.

Under this approach, initial cost shares are based on projected import levels at FID, with periodic adjustments over a 25-year period according to actual import data. As Zone A imported less electricity than expected, it receives € 169 million in annual corrections. Zones B and C, whose imports exceeded projections, contribute an additional € 37 million and € 151 million per year, respectively. Zone D, with slightly lower-than-expected imports, receives € 19 million annually. This dynamic adjustment mechanism ensures that cost allocations agilely evolve in line with realised system benefits, but at the expense of predictability for national budgets.

Methodology 3: Ex-ante scenario-based for transmission and ex-post observed metric-based for generation

Methodology 3 distinguishes between transmission and generation costs, using an ex-ante, scenario-based metric for transmission and an ex-post, flow-based metric for generation. The results are presented in Table 07.

Table 07: Methodology 3 cost-sharing example

Ex-ante (Transmission)

Zone	SEW	Cost sharing ratio	Cost (€ million)
A	17,000	50%	9,000
B	7,500	22%	3,960
C	5,000	15%	2,700
D	4,500	13%	2,340
Total	34,000	-	18,000

Ex-post (Generation)

Zone	Projected Imports (GWh)	Gen Import Share	Ex-ante estimation Cost (€ million)	Observed Imports (GWh)	Gen Import Share	Ex- post observed Cost(€million)	Annual Correction (€ million/year)*
A	32,500	50%	7,000	24,050	37%	5,180	73
B	14,300	22%	3,080	16,250	25%	3,500	-17
C	9,750	15%	2,100	16,900	26%	3,640	-61
D	8,450	13%	1,820	7,800	12%	1,680	5
Total	65,000	100%	14,000	65,000	-	14,000	-

*Annual correction is an average payback over an estimated 25-year period.

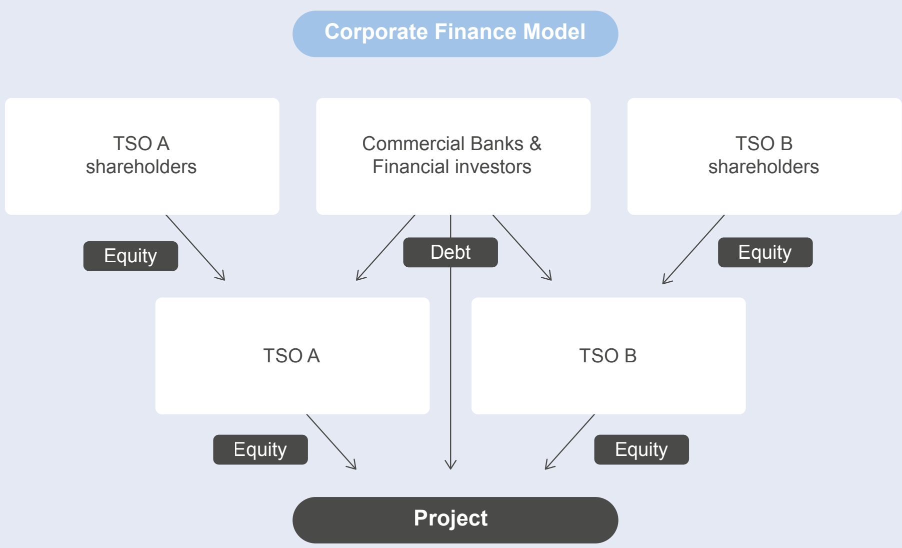
Transmission costs are fixed ex-ante based on forecasted SEW at FID, while generation costs are adjusted ex-post (over 25 years) based on actual import flows. Zone A bears the highest cost (€ 14.2 million, total), primarily due to its significant transmission share. Zones B and C face annual correction payments as their actual generation usage exceeded initial SEW projections. Zone D contributes the least, with both transmission and generation shares remaining below 15%.

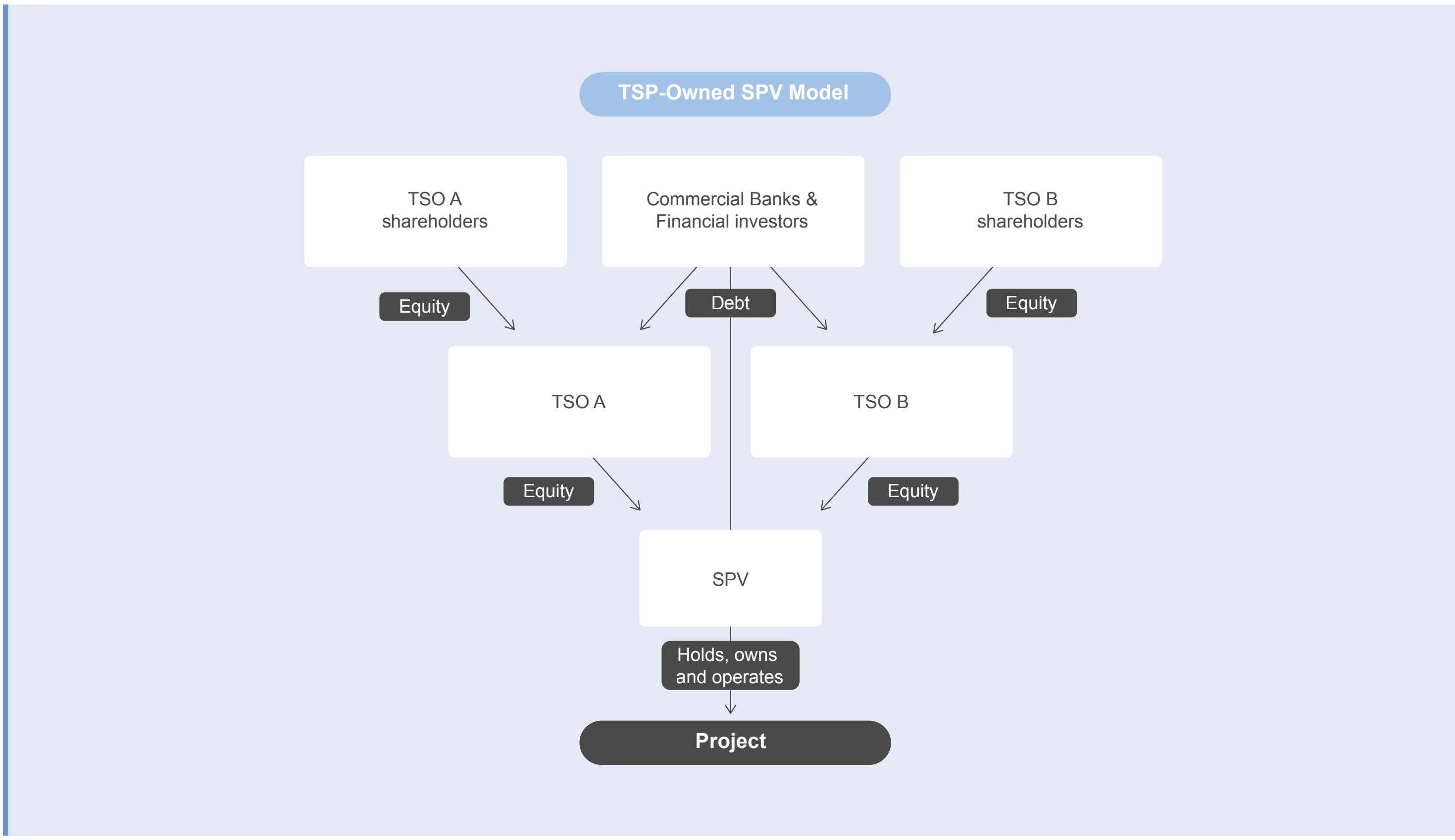
Observations from the cost sharing examples

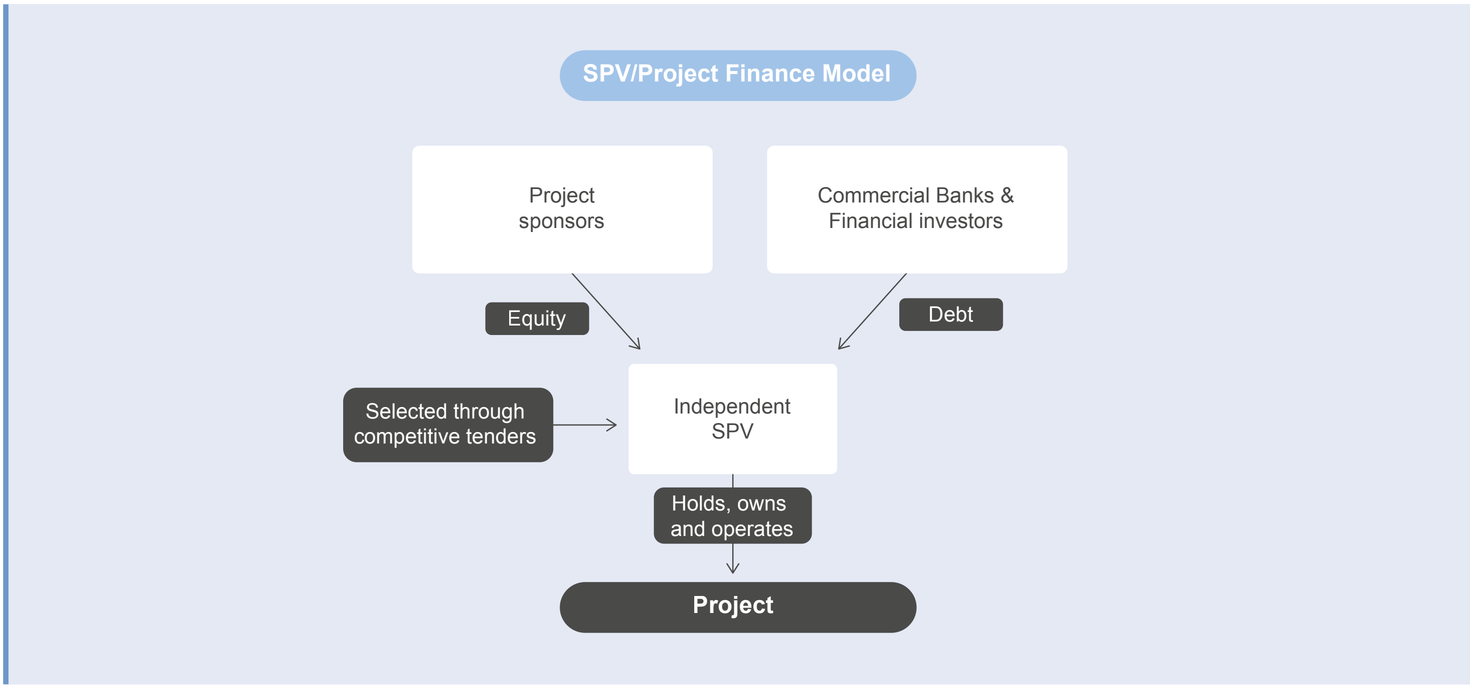
The examples above illustrate how different cost-sharing methodologies impact the allocation of costs among participating countries. Ex-ante scenario-based approaches offer predictability by fixing cost shares in advance but may not reflect real-world benefits if energy market outcomes diverge from projections. In contrast, ex-post approaches better reflect how the actual energy system evolves by offering the agility to account for changing system conditions but introduce uncertainty regarding annual contributions by individual countries. Methodologies mixing approaches can balance predictability and agility but must be carefully designed to maintain stakeholder confidence.

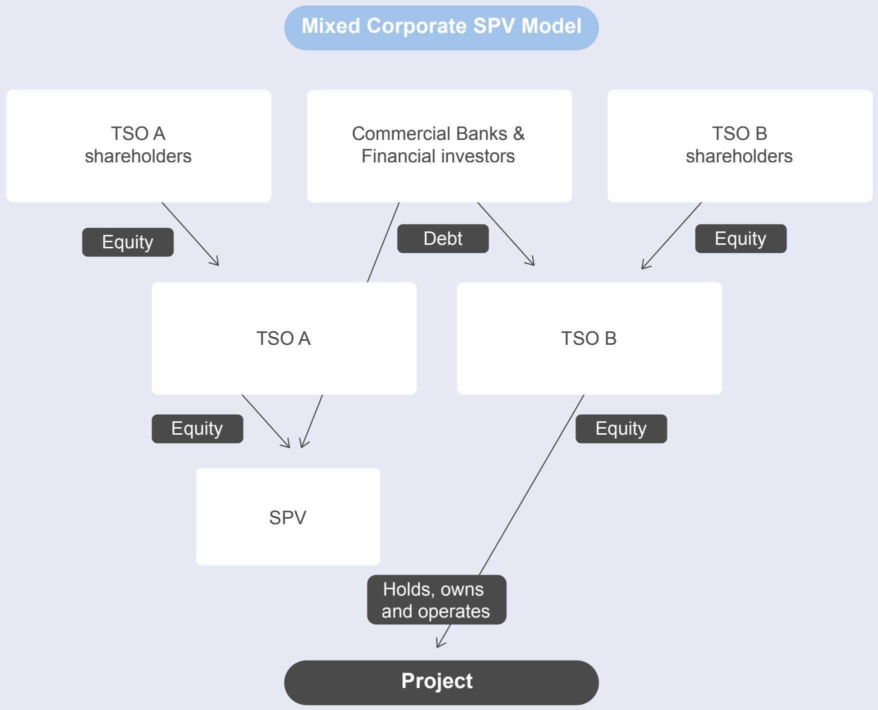
Annex D: Example of financial structures in hybrid projects

Figure 12:
Example of financial structures in hybrid projects




TSP-Owned SPV Model
TSO A
shareholders
Commercial Banks &
Financial investors
TSO B
shareholders
Equity
Debt
Equity
TSO A
TSO B
Equity
Equity
SPV
Holds, owns
and operates
Project


SPV/Project Finance Model
Project
sponsors
Commercial Banks &
Financial investors
Equity
Debt
Selected through
competitive tenders
Independent
SPV
Holds, owns
and operates
Project


Mixed Corporate SPV Model
TSO A
shareholders
Commercial Banks &
Financial investors
TSO B
shareholders
Equity
Debt
Equity
TSO A
TSO B
Equity
Equity
SPV
Holds, owns
and operates
Project

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