cerre Centre on Regulation in Europe

CROSS-BORDER COST ALLOCATION FOR ELECTRICITY TRANSMISSION NETWORKS

REPORT

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CERRE's added value is based on:

- its original, multidisciplinary and cross-sector approach covering various markets, e.g., energy, mobility, sustainability, tech, media, telecom, etc.;
- the widely acknowledged academic credentials and policy experience of its research team and associated staff members;
- its scientific independence and impartiality; and,
- the direct relevance and timeliness of its contributions to the policy and regulatory development process impacting network industry players and the markets for their goods and services.

CERRE's activities include contributions to the development of norms, standards, and policy recommendations related to the regulation of service providers, to the specification of market rules and to improvements in the management of infrastructure in a changing political, economic, technological, and social environment. CERRE's work also aims to clarify the respective roles of market operators, governments, and regulatory authorities, as well as contribute to the enhancement of those organisations' expertise in addressing regulatory issues of relevance to their activities.

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AC	Alternative current
CB RES	Cross-Border Renewable Energy Project
CBA	Cost-benefit analysis
CBCA	Cross-border cost allocation
CEF	Connecting Europe Facility
CfD(s)	Contract(s) for Differences
CO_2	Carbon-dioxide
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
EU	European Union
FTRs	Financial Transmission Rights
HVDC	High-voltage direct current
ITC	Inter-transmission system operator compensation
ONDP	Offshore Networks Development Plan
PCI(s)	Project(s) of Common Interest
PMI(s)	Project(s) of Mutual Interest
PINT	Put in one-at-a-time approach
PPA(s)	Power Purchase Agreements
RED	Renewable Energy Directive
TEN-E	Trans-European Networks for Energy
TFEU	Treaty on the Functioning of the European Union
TOOT	Take-out one-at-a-time approach
TSO(s)	Transmission system operator(s)
TYNDP	Ten-Year Network Development Plan
UK	United Kingdom

Executive Summary

Europe's net zero ambitions depend crucially on the creation of interconnected energy networks. Greater cross-border capacity would unlock trade and technological synergies among Member States. However, it also raises questions of efficiency and fairness—specifically, how to divide costs, structure tariffs, and integrate new assets into existing legal frameworks. Moreover, hybrid offshore interconnections complicate access rights, tariff rules, and renewable energy support schemes, often requiring coordination with regulators both within and outside the European Union (EU).

This report addresses these issues through economic, legal, and empirical lenses, with a special focus on electrical grids. It offers a multidisciplinary perspective that stands out in three ways: it comprehensively reviews the regulatory framework, develops a rigorous analytical framework for comparing alternative cost-sharing formulas, and grounds the analysis in real-world cases that expose regulatory gaps and suggest practical solutions. Together, these methodological elements focus on the governance and financing of transnational grid investments.

Chapter 2 presents a comprehensive review of the current **regulatory framework and its associated challenges**. It first examines the European Ten-Year Network Development Plan (TYNDP) as a tool for evaluating cross-border utility infrastructure investments and determining implementation priorities. The chapter outlines several limitations, including single-project evaluation approaches, a short-term focus, and a lack of cross-sectoral harmonisation. Beyond initial cost-sharing, mechanisms like congestion income handling, bidding zone design, cross-border capacity targets, inter-transmission system operator compensation (ITC), and network tariff structures create implicit cross-border cost transfers. The policies governing these mechanisms significantly influence the distribution of transmission infrastructure costs and benefits among countries. Several challenges remain. Predicting costs and benefits for new hybrid cross-border grids is difficult due to uncertain parameters, uneven gains, and overlapping payment schemes. These gaps give rise to disputes over who should pay or be reimbursed—especially when countries incur net losses or benefit only indirectly. The use of both up-front and after-the-fact settlements can result in double-counting and may deter investors.

Chapter 3 provides a **conceptual framework** for analysing the economic effects of expanding electricity transmission capacity (interconnectors). The underlying mechanism is a *strategic trade effect*, whereby transmission expansion creates opposing price movements: raising prices in exporting regions while lowering them in importing areas. This dynamic creates winners and losers within each country: producers in export areas and consumers in import areas benefit, while consumers in export areas and producers in import areas lose. The magnitude of these price effects determines each country's overall welfare gain. Countries with flatter supply and demand curves (such as resource-rich exporters with abundant renewable sites) experience smaller price changes and thus derive smaller benefits from increased interconnection. This asymmetry, combined with the way investment costs are allocated, may lead to inefficient outcomes, where national incentives diverge from the socially optimal solution. Countries may prioritise national surplus over collective welfare.

The analysis demonstrates how alternative cost-sharing rules (*equal cost-sharing*, *proportional cost allocation*, and *equal net benefit allocation*) can internalise strategic effects by adjusting cost burden based on domestic price responsiveness. Compensating lower-benefiting countries, while charging higher-benefitting ones more, thereby addresses the misalignment between national incentives and social welfare maximisation.

Chapter 4 examines **approaches in practice** for allocating interconnection costs between countries. Cost-sharing arrangements span a broad spectrum, ranging from straightforward methods—such as a 50-50 split or full coverage by the primary beneficiary—to sophisticated agreements based on net benefits across multiple scenarios, potentially including post-implementation settlements when specific conditions are met. Examples from the Nordic countries, Great Britain, France, and Germany, illustrate some of these approaches. The territorial principle, where each transmission system operator (TSO) pays for infrastructure within the borders of its own country, remains the most common approach, as seen in Nordic examples such as Nea-Järpströmmen and Southwest Link. Germany has implemented full-cost socialisation across all four Transmission System Operators (TSOs) to address uneven investment burdens resulting from renewable energy development. Meanwhile, some projects, such as the Aurora Line between Finland and Sweden, have adopted a benefit-based cost allocation, with an 80-20 split reflecting the primary benefits, which are mainly directed to Finland. The Gulf of Biscay project, a collaboration between France and Spain, exemplifies a hybrid approach that combines a 50-50 baseline split with contingent EU funding allocation to ensure project viability for both parties.

Chapter 5 concludes with **policy recommendations**. The EU's electricity grid transformation faces four key challenges: investment risks stemming from uncertain demand and politics, unfair cost-benefit sharing, regulatory gaps between planning and implementation, and insufficient resilience mechanisms. Stakeholders face different trade-offs—TSOs balance risks against expansion needs, Member States weigh sovereignty against coordination, and transit countries bear burdens without control. The EU must balance the need to build the proper infrastructure quickly with the need to manage flexibility versus system-wide efficiency in its shift to a regional interconnected grid.

The report proposes policy recommendations in four key areas of EU cross-border electricity infrastructure:

- Establishing a **layered governance approach** that enables decision-making at EU, regional, and bilateral levels, depending on project complexity, including allowing **TSO co-ownership** across borders;
- Improving **planning** through the use of **stable scenarios and a more integrated cost-benefit analysis (CBA)**, including revising the 15% interconnection target to bidding-zone level, creating binding energy scenario commitments, and aligning congestion rent splits with investment cost shares;
- **Promote better risk allocation** with **cost-sharing agreements based on individual benefits and with any after-the-fact settlement** specified upfront to prevent hold-up problems from future renegotiations when benefits are initially uncertain;
- **Expanding EU financing beyond current mechanisms**, such as the Connecting Europe Facility (CEF), to cover hard-to-quantify benefits, including the security of supply and geopolitical resilience, but potentially also the development of financial transmission corridors or contracts-for-difference mechanisms.

1. Introduction

Europe's net zero ambitions depend crucially on creating interconnected energy networks. Greater cross-border capacity would unlock trade and technological synergies among Member States. However, it also raises questions of efficiency and fairness—specifically, how to divide costs, structure tariffs, and integrate new assets into existing law. Moreover, hybrid offshore interconnections complicate access rights, tariff rules, and renewable energy support schemes, often requiring coordination with regulators both within and outside the EU.

This report examines the need for additional measures to facilitate investment in electricity network infrastructure, with a particular focus on **cross-border networks**. Building upon economic theory, legal analysis, and evaluation of existing practices, as well as policy proposals and case studies on the European Union (EU) and beyond, this study formulates a set of **policy recommendations** for governance, network planning, risk sharing, and financing.

The focus is on mechanisms for allocating **costs, benefits, and risks** among Member States. The matter requires an evaluation of both **efficiency and equity considerations** of cost allocations, their implications for network tariffication (e.g., to generators and consumers), and interactions with existing legislation (such as market design, solidarity principles, and the 70% minimum availability requirement). To evaluate equity concerns, we must consider not only who bears the investment costs and risk, but also who benefits from the new transmission capacity.

Our focus will be on electricity networks, where we examine both sharing and extending **existing networks,** as well as building **new networks (offshore)**. Offshore networks are essential for the integration of offshore wind energy into the European energy system, and they are often more challenging than onshore interconnectors. This is due to a higher uncertainty on future energy scenarios, economies of scale in grid expansion not yet realised, and market design and bidding zones not yet established. Offshore interconnections are often hybrid, involving offshore generators, and feature complex interactions with other policies such as network access rights, network tariffication, and RES support schemes. In addition, offshore links often involve coupling with third states, such as the United Kingdom (UK) and Norway, which have differing legal and regulatory regimes.

The report complements CERRE's study "*Scaling up Offshore Wind Energy in Europe*" (Banet & Willems, 2023), which looks more closely at regulating offshore wind and the interactions between network regulation, support schemes for renewable energy, market design and the hybrid interconnectors that also serve to connect offshore wind farms. It is also complementary to CERRE's study "*Towards a More Dynamic Regulation for Energy Networks*"(Pollitt et al., 2014), which examines changes in network regulation in a net-zero future, proposes incentives for networks to innovate, and presents findings from expert and stakeholder surveys.

1.1. Context

Interconnected energy networks capable of offering stability to EU systems are the backbone of the green energy transition and security of supply. The continued integration of the European electricity markets, as shown in CERRE's modelling of a net zero energy system (Chyong et al., 2021), relies on accessing the wind and solar resources concentrated in the North Sea and in Southern Europe. This will allow Europe to complete its decarbonisation by combining renewables and hydrogen. In addition, another building block of net zero is carbon capture, utilisation, and storage (CCUS), with storage in the North Sea. In this context, a key role for the European Union and its closer neighbours is **to jointly facilitate cross-border interconnection of electricity, hydrogen, and carbon dioxide (CO_2) networks**.

In 2023, the European Commission launched the **EU Grid Action Plan** (European Commission, 2023), which aims to facilitate investment in electricity grids and promote more efficient operation. The Plan stresses that networks will need to adapt to increased digitalisation and decentralisation, flexibility needs will rise with new solar PV, heat pumps and electric mobility, and the system will also need to accommodate offshore renewables and hydrogen. **The investment required to support this transformation is estimated at €300-600 billion**. Among its main proposals, the EU Grid Action Plan calls for stronger political guidance to accelerate the implementation of Projects of Common Interest (PCIs); the introduction of **regulatory incentives** through guidance on anticipatory, forward-looking investments and cross-border cost-sharing for offshore projects; and improved financial access for grid-related projects. In a Guidance document on anticipatory investments (European Commission, 2025), the Commission details specific actions in the realms of network planning, regulatory approval, and network tariffs to overcome the uncertainty and anticipatory nature of network investments for the energy transition. At the 11th Energy Infrastructure Forum, the Commission also outlined further steps linked to cross-border cost-sharing in the regulatory incentive dimension of the Action Plan, encouraging TSOs to explore the potential of regional coordination, leading to a cost-sharing-related policy paper by ACER, as well as knowledge sharing on pilot concepts.

Our project contributes to this discussion, and thereby also to enhanced grid interconnection in Europe and the energy transition at large.

1.2. Research Questions

This new regulatory context raises a series of questions. We address the topics below:

- How should countries, regulatory authorities and project developers allocate the costs of new interconnectors? What are the efficiency and equity considerations?
- How does the market design (congestion, access rights, bidding zone delineation) affect the allocation of the benefits and risks to stakeholders, and how should this be considered for the cost allocation?
- Which instruments and mechanisms can we use to allocate costs (such as grid tariffs, direct transfers, and co-ownership of assets)?
- Is the current governance structure sufficient to address the questions above for concrete projects? If not, what is a good governance structure for settling these questions? What is the role of the different stakeholders in this process? What is the role of network users (e.g. new wind farm operators) in this process? Should planning and cost allocation be combined in a single process?
- How can the processes of the PCIs and Project of Mutual Interest (PMIs) be concretely improved?

1.3. Methodological Approach

Next to a literature review, legal and economic analysis, we evaluate some policy proposals and conduct case studies. Case studies were chosen based on the authors' expertise and suggestions from CERRE members. Each case study focuses on a particular cost-sharing arrangement, as follows:

- Territorial cost split
- Equal cost split
- Full socialisation
- Net benefit sharing
- Cost-sharing agreement contingent on EU funding

2. Policy Debate

2.1. The Need for Infrastructure

The need for more cross-border electricity has long been acknowledged by the European Union as an important pillar to create the internal energy market. This has been reflected in the interconnection targets of 10% by 2020, and 15% by 2030, laid down by the Council (see also Section 2.2.3). The energy transition makes the need for more (cross-border) electricity infrastructure increasingly pressing. Connections over larger distances make the impact of weather differences smaller and help to spread peaks in electricity demand (especially when stretched over different time zones).

Offshore wind in particular plays a central role in the EU's decarbonisation strategy, but its integration poses specific challenges. The EU installed 12.9 GW of new wind capacity in 2024 and is projected to install an additional 140 GW between 2025 and 2030—an average of 23 GW per year (WindEurope, 2025). With the current projected volumes of offshore wind in the EU, the offshore wind output of some countries (or regions) exceeds their demand for electricity in the coastal countries. This surplus requires additional electricity infrastructure to transport the offshore-generated electricity to major load centres, and across borders to neighbouring countries. ENTSO-E (2024b) estimates that, by 2050, Europe will require an additional 54,000 km of offshore transmission infrastructure, compared to 2025.

Until now, almost all offshore wind capacity has been radially connected. In several cases, the expansion of offshore wind farms also brings the opportunity for realising hybrid interconnectors, i.e. infrastructure that simultaneously serves the dual purpose of connecting offshore generation to shore and interconnecting the electricity systems of two or more countries/market zones (See (Banet & Willems, 2023). According to ENTSO-E (2024b), by 2050, 80 GW of offshore wind can be connected to two or more countries, rather than one. Hybrid interconnectors can bring efficiency in reduced costs, reduced amounts of material needed and reduced space usage for the cables in the seabed (compared to separate interconnectors and radial cables). However, to date, only one hybrid asset has been realised: the Kriegers Flak Combined Grid Solution, connecting the grid of north-eastern Germany with the Danish island of Zealand. This limited progress is largely due to legal challenges within the current regulatory framework, which will be explored in the next section.

2.2. Existing Policies

2.2.1. Trans-European Energy Network Development

The foundational competence for developing and stimulating trans-European networks is laid down in Art. 171 of the Treaty on the Functioning of the EU (TFEU) as well as in Art. 194(1)d TFEU ("*to promote the interconnection of energy networks*"). Regulations (EC) 714/2009 and 715/2009 historically established a process of community-wide planning of "*viable [electricity and gas] transmission networks and necessary regional interconnections, relevant from a commercial or security of supply point of view*" (European Union, 2009a, 2009b).

Regulation (EU) 347/2013 on trans-European networks for energy, also known as the TEN-E Regulation, further elaborates this process and the CBA at the basis of the selection of Projects of Common Interest (PCIs) (European Union, 2013).[1] The Regulation has been revised in 2022, to introduce mandatory sustainability criteria for all PCI projects, to include project connecting the EU with third countries (PMIs), and to provide more structure for voluntary cooperation among Member States on offshore grid planning (European Union, 2022b).

According to the TEN-E Regulation, the two European Networks of Transmission System Operators for Electricity (ENTSO-E) and Gas (ENTSO-G), which govern the development of energy networks, are mandated to develop scenarios for the future of the European energy system in the context of their respective Ten-Year Network Development Plans (TYNDPs). This biennial planning exercise serves as a key instrument for streamlining the planning of network interconnections in Europe, specifically by pointing out at remaining infrastructure gaps in the current planning and providing a CBA of proposed additional projects.

A TYNDP cycle starts with building scenarios and translating them into comprehensive input data, for example, on demands and plant capacities. In order to account for the long lifespan and considerable lead times for the commissioning of network infrastructure, scenarios and modelling cover a timeframe of 15 to 25 years, i.e., until 2040 and 2050. The 2024 cycle of the TYNDP included three scenarios, reflecting:

- a projection of the existing plans by the individual member states until 2040 (National Trends+ scenario);
- a centralised energy system that is well interconnected beyond the European Union (Global Ambition scenario); and
- a comparatively decentralised energy system, more focussed on the community level and domestic energy security (Distributed Energy scenario).

Based on the scenario inputs, market and network modelling reveal the need for additional network capacity across Europe. Then, infrastructure developers, such as individual TSOs, can promote their projects to the TYNDP for CBA.[2] Point 3(a) and (d) of Art. 4 of the TEN-E regulation specify sustainability, security of supply and market integration as the main dimensions for the CBA for electricity, natural gas and hydrogen transmission infrastructure. Respectively:

- sustainability captures the integration of energy from renewable and variable sources;
- security of supply encompasses appropriate interconnections and secure and reliable system operation, interoperability, system flexibility, and cybersecurity; and
- market integration (and competition) covers the aspects of market interconnections and lifting the electrical isolation of Member States.

These dimensions are captured via a set of indicators discussed in the next section (2.2.2).

[1] Next to Projects of Common Interests (PCIs), which focus on projects inside the European Union, there also exist Projects of Mutual Interest (PMIs) for projects between European Member States and a third country outside the Union, with similar provisions.

[2] For project examples in the TYNDP 2022 see: https://tyndp2022-project-platform.azurewebsites.net/projectsheets/transmission.

Project promoters can apply for the status of a PCI to benefit from:

- simplified regulatory responsibilities, including for example that for offshore projects national regulatory and permitting authorities must cooperate amongst themselves and jointly designate single points of contact across the concerned national jurisdictions;
- accelerated permit granting, including prioritised handling by the national authorities and the presumption of overriding national interest; and
- the option to apply for funding from the Connecting Europe Facility (CEF).

Applications for PCI status are assessed by so-called 'regional groups', which are chaired by the European Commission and include representatives from Member States, TSOs, ENTSO-E or ENTSO-G, national regulatory authorities and the Agency for the Cooperation of Energy Regulators (ACER). PCIs can apply for CEF funding for 'studies', i.e. preparatory assessments, evaluations and testing, or for 'works', i.e. procurement of components and construction and installation activities. These applications are assessed by an independent expert pool selected by the European Climate, Infrastructure and Environment Executive Agency (CINEA). The budget allocated for these activities in 2024 was €850 million and most applications were for studies (CINEA, 2024).

In cross-border projects, the cost of the infrastructure is often shared between neighbouring TSOs. This means that, in such arrangements, each part of the infrastructure is assigned to the regulated asset base of one of the involved TSOs and will be recovered via their respective network tariff, i.e. from their national network users. Any proposed cost-sharing arrangement must therefore be approved by national regulatory authorities, and in case of disagreements among them, ACER serves as a last-resort decision maker. Mostly for reasons of simplicity, it is common to assign the assets to the TSO on whose territory they are built (territoriality principle), or by a simple 50/50 arrangement (ACER, 2020). When PCI projects reach sufficient maturity, with an up-to-date project-specific CBA, and within 36 months of the estimated start of the construction phase, the project developers shall submit an investment request, which shall include a request for a cross-border cost allocation, to be submitted to all relevant national regulatory authorities.

In parallel to the framework for energy grids, Regulation (EU) 2021/1153 establishing the Connecting Europe Facility, and the recast of the Renewable Energy Directive (EU) 2023/2413, also known as the RED III Directive, set a framework for cross-border renewable generation infrastructure (European Union, 2018a, 2021). For these projects, Member States can agree on:

- statistical transfers of energy generation from renewable energy sources (RES) for national targets (Art. 8), and/or
- cross-border support schemes (Art. 13).

Projects with a positive CBA in the dimensions of energy generation, system integration and support costs, greenhouse gas emissions and local (air) pollution, security of supply and innovation can obtain the status of a Cross-Border Renewable Energy (CB RES) project. Similar to the PCI status, the CB RES comes with streamlined permitting procedures and the option to apply for CEF funding for studies and works.

In 2024, the first Offshore Network Development Plan (ONDP) was published alongside these processes to capture the immense infrastructure build-out in several European sea basins (ENTSO-E, 2024b). The first assessment of offshore infrastructure was made outside the regular TYNDP cycle to prevent delaying its regular process with the special challenges of this new analysis. In the future, the assessment of offshore infrastructure shall be streamlined in the TYNDP process.

2.2.2. Cost-Benefit Studies in Practice

Cost-benefit analyses support informed decision-making. Among others, they determine which projects qualify for PCI status and play an important role in the planning and development of the future energy system.

This section discusses existing frameworks for project-specific CBA as envisioned by the ENTSO-E guidelines (ENTSO-E, 2024a).[3] The goal of these project-specific CBAs is the assessment of the marginal benefits that a project will create. They assess the benefits of an infrastructure project by comparing the network configuration with the project (the factual), to an alternative network configuration without the project (the counterfactual) and calculate the project's marginal contribution to a set of key benefit indicators.

Both the ENTSO-E and ENTSO-G analyses combine a monetary cost-benefit analysis with a multi-criteria analysis. This means that certain benefit indicators are quantified in monetary terms, while others are assessed either qualitatively or through other non-monetary values. An overview of the benefit indicators used by ENTSO-E for transmission infrastructure is provided in Table 1. These benefit indicators are aligned with the three main criteria outlined in the TEN-E Regulation: sustainability, security of supply and market integration. The table is based on ENTSO-E Guideline for CBAs of grid development projects, where further elaboration of the respective indicators can be found as well (ENTSO-E, 2024a).[4]

The cost-benefit analysis begins by defining a reference network. It represents a forecasted state of the transmission network and includes all projects with a high likelihood of completion by the simulation year. To evaluate the marginal benefits of a project that is included in the reference network, the '*Take-out one-at-a-time'* (TOOT) approach is used. The reference network is the factual, and the counterfactual is the reference network minus the project. To evaluate the marginal benefits of a project that is not included in the reference network, the '*Put in one-at-a-time'* (PINT) approach is used. The reference network is now used as the counterfactual and the reference network with the project added to it is the factual.

The existing framework has some limitations. First, by considering only single project deviations (addition or subtraction) of the reference network, the CBA might not select the best set of projects to implement when assessing clustered or interrelated projects. This is the case because the value of project A depends on which other projects are implemented. The benefit function is not additive in

[3] ENTSO-E and ENTSO-G published the first drafts of their respective guidelines in 2015. They have undergone continuous updates since. The guidelines implement the principles of the TEN-E regulation (EC 347/2013) and are used for the bi-annual evaluation of projects in the TYNDP.

[4] See Chapter 5.

Table 1: ENTSO-E benefit indicators for transmission infrastructure projects.

Indicator	Unit	Approach	TEN-E Criteria
Socio-economic Welfare	€/yr	Short-run economic rents: consumer, producer and congestion, cross-sectoral and storage. Calculated through an interlinked hydrogen and electricity market model.	Market integration, Sustainability
CO_2 emissions	Tons/yr €/yr	Emission reduction is first expressed in tons to align with political targets. Emission trading is already incorporated into SEW benefits. To avoid double-counting, the difference between the social cost of carbon and the ETS price is considered as an additional monetary benefit.[5]	Sustainability
Renewables integration	MW MWh/yr	The reduction of renewable curtailment and/or the amount of renewable capacity directly connected by the project, calculated through market and redispatch simulations.[6]	Sustainability
Non-CO_2 emissions	Tons/yr	Calculated based on yearly power plant generation patterns [MWh] and emission factors [t/MWh] through market and redispatch simulations. Possible emissions include NO, CO, SO_2, and particulates.	Sustainability
Grid losses	MWh/yr	Losses are calculated through power flow simulations. Demand curves already include grid losses as they are based on historical time series. Compensation is, therefore, necessary to avoid double-counting with SEW.	Energy efficiency
Adequacy	MWh/yr	Expected energy not served is calculated using Monte Carlo-based Market simulations. Note that the adequacy assessments are calculated assuming fixed generation capacities.	Security of Supply
Flexibility	Ordinal	Methodology is under development.	Security of Supply

[5] Three values are based on the "*Handbook on the external costs of transport*". (Low = 60, Central = 100, High = 189 euro/ton) Low and High values are only used in the NT+2030 scenario. If the SCC is lower than the ETS price it is not calculated. Any reduction of CO_2 emissions in a sector covered by ETS will not result in an overall reduction of emissions unless, through the market stability reserve, the number of permits at the EU level is reduced. It is not clear to us how those reductions are taken into account.

[6] For onshore projects, generation levels are given based on projected zonal generation capacities and are assumed to be fixed. For offshore hybrid projects, ACER proposes to take the windfarm as given and assume that a radial line would be necessary if the hybrid project would not be built.

Indicator	Unit	Approach	TEN-E Criteria
Stability	Ordinal	Methodology is under development.	Security of Supply
Reduction of necessary reserve for redispatch power plants	MWh/yr	The maximum redispatch power is calculated through redispatch simulations. It serves as a proxy for the required redispatch capacity. Some countries have specific mechanisms for contracting redispatch reserve power plants.	Security of Supply

Source: ENTSO-E (2024), 4th Guideline for Cost-Benefit Analysis of Grid Development Projects, 2024.

the project implementation. Projects A and B can be complementary to each other (the value of project A increases with the implementation of project B), or substitutes (the value of project A decreases with the implementation of project B).

The combination of the non-additivity and single project-by-project evaluation can lead to unexpected results. Suppose four projects are being considered: {A, B, C, D}, and the reference network contains the projects {A, B}. In case C and D are complementary to each other, the PINT approach might give each individual project a low level of benefit, but the joint investment might create large benefits. In case C and D are substitutes, the PINT approach might give both projects a positive evaluation but investing in both projects might be sub-optimal. In case C and B are close substitutes, the PINT approach may give a low value for C (as B is assumed to be built anyway) and the TOOT approach may give a high value for B (as C is not considered as a potential alternative investment). So, project B, which is part of the reference network is more likely to be invested in, than project C which is not part of the reference network.

ENTSO-E's current cost-benefit analysis focuses primarily on the short-term benefits of infrastructure projects and lacks long-term assessments. A complete CBA is only conducted for the NT+2030 scenario, a National Trends scenario that simulates the year 2030 and aligns with the Member States' National Energy and Climate Plans (NECPs). For the 2040 scenarios, a subset of indicators is calculated, and no simulations are performed for the 2050 scenarios. Furthermore, ACER highlighted that all analyses are based on historical weather data, which under the influence of climate change, may no longer accurately represent future conditions (ACER, 2023).

ACER (2023) additionally noted that the 4th and latest ENTSO-E CBA Guideline does not identify Member States experiencing net positive or net negative impacts from a given project. This calculation, however, is mandated by the TEN-E Regulation and will become increasingly important for sea-basin cost allocation exercises. In fact, ENTSO-E has announced to its stakeholders that this will be included in the upcoming assessments of the ONDP clusters.

Finally, there is a lack of harmonisation of CBAs across sectors. ENTSO-E and ENTSO-G are making efforts to align assumptions in their CBA methodologies, such as discount rates and monetisation coefficients for benefits and have largely aligned their underlying scenarios. This harmonisation could be extended beyond the gas and electricity sector. Other infrastructure categories, such CO_2 networks, or smart grid projects eligible for the PCI status, lack equivalent coordinated assessment frameworks. Although guidelines exist, the absence of centralised calculations or datasets for project promoters can result in inconsistent outcomes.

In the ONDP, ENTSO-E identifies transmission infrastructure needs for the five priority offshore grid corridors,[7] and will perform sea-basin-wide CBAs for each of them. The CBAs evaluate the benefits of the overall corridor, rather than individual projects. In June 2024, the European Commission published a Guidance on how to conduct such sea-basin-wide assessments, in order to address many of the limitations of the project-specific CBAs mentioned earlier, and emphasise the need for long-term assessments (European Commission, 2024). Simulations are required for the years 2040 and 2050, and stress that the CBAs must identify net beneficiaries to facilitate cross-border cost allocation.

However, some open questions remain. First, while the Guidance acknowledges the challenges of determining an appropriate counterfactual for the full sea basin, it places the responsibility on Member States to provide input for a realistic alternative configuration. Second, the Guidance is limited in scope to the electricity sector, with cross-sectoral harmonisation deferred to a later stage. Some of these issues may be further clarified in the ENTSO-E's forthcoming implementation Guideline, expected in June 2025.

2.2.3. Other Regulations Affecting Allocations

Aside from the cost-sharing arrangement at the initial investment stage described so far, there are several other mechanisms and policies that effectively can allocate grid infrastructure-related costs across borders. These include the handling of congestion income, the sizing of bidding zones, targets for the availability of cross-border transmission capacity, the inter-TSO compensation mechanism, the specific design of network tariffs and regulatory exemptions for merchant infrastructure.

In the European framework, **congestion income** accrues to the respective infrastructure owners when inter-zonal capacity is constrained. This can follow both implicitly from the spot market if there is a price difference between two bidding zones or via an explicit auction of transmission rights on a specific interconnector. The use of the congestion revenue is restricted by the Regulation on the internal electricity market primarily (1) to guarantee the availability of allocated capacity (Art. 19 §2a) and (2) for maintaining or increasing cross-zonal capacities (Art. 19 §2a) (European Union, 2019). After these objectives have been achieved, national regulatory authorities may approve the use for (Art. 19 §3) a reduction of network tariffs or for holding in a separate internal account for future use according to the above objectives (European Union, 2019).

In 2021, national regulatory authorities reported to ACER on the use of €6.9 billion of overall congestion income (ACER, 2022). 45% was used on the priority objectives and 49% was saved on internal accounts. The remainder was used partly to reduce tariffs and partly to cover tax obligations

[7] Those five corridors are identified by the TEN-E Regulation as the North Seas offshore grids corridor, the Baltic Energy Market Interconnection Plan, the South and West offshore grids, the South and East offshore grids and the Atlantic offshore grids

incurred by the transmission system operators. In 2022, in the Regulation on an emergency intervention to address high energy prices, these restrictions were temporarily altered to allow for congestion incomes to finance measures in support of final electricity customers (European Union, 2022a).

The **sizing and shape of bidding zones** have an immediate effect on the congestion income and its distribution among TSOs. Generally, zone borders should reflect structural physical congestion. Due to political reasons and for considerations of liquidity within the zones, some inner-zonal congestion is also resolved with a uniform price zone via redispatch. The cost for this accrues to the TSO and is usually passed on to network users via tariffs.

Similarly, the actual **availability of cross-border capacity** affects prices in the bordering market zones, ultimately influencing both congestion revenues and TSO revenues. Regulation (EU) 2019/943 specifies that the maximum capacity of interconnections and the transmission networks affected by cross-border capacity shall be made available to the market (Art. 16(4)), in compliance with safety standards of secure network operation (European Union, 2019). Counter-trading and redispatch, including cross-border redispatch, shall be used to maximise the available capacities. This provision clearly prohibits TSOs from shifting congestion to the border or from solving internal congestion by reducing the capacity of interconnectors. Art. 16(8) further quantifies this by adding that 70% of the cross-border grid capacity is made available for trading. These requirements might disincentivise TSOs from upgrading their cross-border transmission capacity, as far as their national grid cannot deal with the extra flows. The minimum 70% target might also complicate the development of hybrid interconnector projects, especially where offshore wind farms seek both grid access and price guarantees on an offshore cable which also acts as an interconnector (See also (Banet & Willems, 2023). The 2014 interconnection targets set by the European Council encourage Member States to increase the cross-border interconnection capacity, and were later reflected in the Governance of the Energy Union Regulation, which aims for a 10% electricity interconnection by 2020 and at least 15% by 2030 (European Union, 2018b).

Furthermore, Regulation (EU) 838/2010 features an **inter-TSO compensation mechanism** that establishes transfers to TSOs hosting cross-border flows in their networks, thus compensating for the losses incurred as a consequence of these flows, and also for the cost of upgrading their infrastructure for this purpose (European Commission, 2010). The amount to be transferred for the latter is capped at €100 million, largely as a result of tedious negotiations. The size of the transfer fund for losses varies depending on the actual cost and state of the system. In 2023 around €1.24 billion were transferred, marking a steep increase from pre-crisis levels of only around €200 million (ACER, 2025). The mechanism has been highly controversial during its inception and at least the execution of the settlement for losses continues to cause debate between TSOs due to heterogeneous national frameworks.

Another implicit transfer between countries could result from differences in **network tariff design**. In a net exporting region, high generation (injection) charges allow the network operator to recover some of the network costs from consumers abroad, provided that these generation charges are passed on into the energy price and there is no congestion on the transmission line.[8] There are significant differences in tariffication across the EU. Eleven Member States do not impose an injection charge for generation. For the ones that do, the share of injection charges varies from 3% to 35% of the transmission costs (ACER, 2023).

Guidelines and regulations limit the size of the injection charges. Regulation (EU) 838/2010 Annex, Part B puts a cap on the part of the total transmission injection tariff that is not directly attributable to the generation (connection charges, ancillary energy charges and losses) (European Commission, 2010). ACER (2014) argues that cost-reflexivity would require the energy component charge only to cover ancillary energy charges and losses, however, ACER (2023) recognises that tariff setting requires trade-offs across multiple objectives, including equity, cost recovery, efficiency, etc. The Report also states that most NRAs believe the current generation charges (given their relatively low levels) do not distort international competition.

The Electricity Regulation and Directives foresee **regulatory exemptions** for new (or large upgrades in) interconnectors, under the conditions set forward in Art. 63 of the Regulation (EU) 2019/943 (European Union, 2019). These exemptions are concluded on a case-by-case basis and require among other that the investments are pro-competitive, the level of risk associated with the investment is such that it would not have taken place without exemption, and that the interconnector owner is legally unbundled from the system operator ("a merchant operator").[9] The exemptions could relate to third-party access, ownership unbundling, network codes, and earmarking of congestion revenue. Next to the exemption for new interconnectors, other deviations are possible. The Kriegers Flak Combined Grid Solution project received a derogation for 'small isolated systems' meaning that it could reserve the availability of interconnection capacity for the connected wind farms, making only the remaining capacity after deduction of the forecasted wind capacity available to market participants.

Table 2 collects the budgets of the above-mentioned mechanisms, in so far as information is available. For comparison, the TYNDP 2024 identifies investment needs ranging from €5 billion annually in 2030 to €13 billion in 2050. Transfers due to asymmetrical generation charges, unavailability of up to 30% of interconnector capacity and regulatory exemptions, as well as future changes to congestion rents via bidding zone adjustments cannot readily be quantified, but we provide some estimates on order of magnitude.[10]

Differences in the injection charges are estimated assuming that: i) the energy component of the generation charges is less than 1.2 €/MWh[11]; ii) the generation chargers are 100% passed on to consumers (so there is no cross-border congestion and consumer demand is inelastic); iii) total net trade in Europe is 148TWh/year.[12]

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[8] This is also formally confirmed in a recent analysis by Neon & Consentec (2025) for TenneT "Injection charges for cross-border grid cost recovery".
[9] Since 2016, 19 exemption projects received exemptions. See: https://energy.ec.europa.eu/topics/markets-and-consumers/wholesale-energy-market/access-infrastructure-exemptions-and-derogations_en .
[10] This table combines data from different sources, cover different years and somewhat different geographical scope.
[11] Regulation 838/2010 limits the generation charge to 0.5 €/ MWh or 1.2 €/ MWh for EU countries.
[12] See: https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Electricity_and_heat_statistics#Import_and_export_of_electricity

Table 2: Overview of funding and cost-sharing mechanisms for the build-out of transmission infrastructure and their budgets.

Mechanism	Approach	Budget
Investment Needs	Identified in TYNDP 2024.	€5 to 13 billion per year
CEF-Funding	Ex-ante grant for 'studies' or 'works' from EU budget.	€0.8 billion per year.[13]
Congestion Income	Continuous transfers from market participants (i.e., demand in high-price zones) to TSOs based on price differences between market zones	€6.9 billion per year (data 2021) between all European bidding zones, incl. domestic zone borders, and zone borders where expansion does not have a positive cost-benefit (ACER, 2022).
Inter-TSO compensation	Continuous settlements between TSOs reflecting losses and loop flows.	€0.1 billion per year (cap for infrastructure update binding since 2011). €1.24 billion per year (data 2023) for losses (ACER, 2025).
70% capacity available for trade	Aiming for 70% available capacity increases congestion management costs.	> €4 billion per year. Rough estimate: The congestion management cost for TSO is probably a lower boundary, as many Member States do not reach the 70% openness (ACER, 2024).
Transfer due to differences in generation charges	Higher injection charges in exporting countries will shift cost recovery to consumers in importing countries.	< €0.18 billion per year. Own calculations.

Source: elaborated by the authors.

To obtain an order of magnitude of the effect of the 70% availability rule we look at the congestion management costs of the TSOs. This is currently about €4 billion per year. This is a lower boundary of the costs, as many Member States do not yet reach the 70% openness rule.

Increasing the number of bidding zones will lower the congestion management costs and will likely reduce the congestion revenue for cross-border capacity, as congestion might become national.

2.3. Challenges of Existing Regulation

2.3.1. Challenges and Opportunities

Cost-sharing for new infrastructure is often controversial. The infrastructures in question are becoming increasingly complex as they evolve from mere interconnectors to hybrid infrastructures, with risks related to the deployment of new technologies, such as the shift from alternating current

[13] €5.8 billion was budgeted for 7 years, covering both PCIs and PMIs. See: https://energy.ec.europa.eu/topics/infrastructure/projects-common-interest-and-projects-mutual-interest/funding-pcis-and-pmis_en.
In 2024, €850 million was requested for selected PCIs. See: https://cinea.ec.europa.eu/news-events/news/cef-energy-74-projects-requesting-approximately-eu4-billion-under-pci-pmi-calls-2024-11-22_en

(AC) to high-voltage direct current (HVDC), and new bidding zone layouts. In addition, the framework of infrastructure-related cross-border cost-sharing is a mosaic of different mechanisms with both explicit and implicit transfers. To an extent, this does justice to the different effects of interconnections, yet it is also partly a result of historical path dependency.

The **ex-ante cost-benefit analysis lies at the core** of cost-sharing arrangements for cross-border infrastructure projects. In principle, it provides a solid foundation for cost allocation, considering a broad range of benefits and impacts. In practice, however, it presents a number of challenges.

Firstly, given its 'ex ante' nature, the analysis is subject to *significant uncertainty* concerning the cost and benefits assessed, as well as the underlying assumptions and future scenarios, especially considering the long lifetime of grid assets. In highly political negotiations, such uncertainties can easily undermine consensus or hinder compromise, particularly when countries have opposing exposures to these risks. In theory, this uncertainty could be at least partially mitigated through ex-post settlements based on actual usage and flows. Part of the uncertainty also relates to the development of new large generators (such as wind farms), the effect of sector coupling, and the provision of flexibility. This implies that future cost-benefit studies may have to consider simultaneously investments in generation capacity and transmission. They can no longer be considered separately.

Furthermore, and notwithstanding any uncertainty, the CBA for large, cross-border infrastructures is quite *complex*. Getting all the parties involved, or even more difficult, all the parties concerned, to agree on assumptions and scenarios can be time-consuming (as can be seen in the TYNDP process). Another decisive and therefore easily controversial question lies in defining the counterfactual for the analysis (see also section 3.2.2. and 4.2).[14]

Lastly, there are several aspects in the CBA where *processes and impacts are rather intangible*. In areas such as the contributions of infrastructure to EU goals (decarbonisation and RES goals),[15] security of supply or cybersecurity, a quantification or even monetisation of cost and benefits remains difficult. Other aspects, like the distributional effects of changes in tax revenues and network tariffs and interaction with industrial policies (employment, technology), are currently not considered. Also, the assessment methods as such can be controversial, especially for innovative and system-related costs or benefits, such as flexibilities or aspects related to the integration of offshore systems.

Taken together, the above challenges erode the CBA as a unanimous and clear reference point for cost-sharing agreements. For simplicity reasons, in the past interconnectors were often built with ex-ante cost-sharing based on the territorial principle or a simple 50-50 rule. However, with increasing investments, involved parties will be less and less willing to rely on such heuristics.

Further challenges gaining importance are those of *net-negative benefits* and *third-party beneficiaries*. Doing justice to countries which are negatively affected by new infrastructure might necessitate

[14] Shu and Mays (2025) address several challenges related to uncertainty in cost-sharing exercises. They conclude that a portfolio of projects reduces uncertainty compared to individual projects and that negotiations can be facilitated by addressing participant-level risks and compensating negatively affected parties.

[15] In a first approximation, the carbon price reflects the current social value of a CO_2 reduction, but it might not reflect the long-run value of a reduction of carbon emissions. Network infrastructure investments might also affect the cost of reaching the EU's renewable energy goals, as it could lower the level of subsidies.

compensation payments, which in turn increase the 'costs' borne by those who benefit. Whether those 'net-negative beneficiaries' host the infrastructure or not determines the extent of their leverage to oppose investments or demand compensation. So, it might be hard for third-party countries to get compensated for their losses. Third-party countries may also benefit from investments. Conceptually, this might justify their financial contributions to the project, for instance, on a voluntary, negotiated basis. If the benefits are widely spread over Member States, socialisation through EU funding can be considered just. If there is no binding compensation for the benefits, countries are also able to free ride on infrastructures developed by and paid for by others. This is the case particularly if benefits to a specific party are small (as compared to the overall cost-benefit assessment) or if they are particularly uncertain.

As the European grid becomes more interconnected, the cross-country benefits are likely to increase. For example, a massive development of wind energy in the North Sea could make the Netherlands a transit country for German and Belgian consumers.[16] Similar issues are likely to arise in most regions.

The framework for cost-sharing effectively already includes several **other ex-post transfer mechanisms,** as discussed in Section 2.2.3. The debate around the infrastructure cost-related part of the inter-TSO compensation mechanism highlights both the methodological difficulties and the political dimension of such a continuous settlement mechanism (ACER, 2014). Given the complexity of meshed electricity grids, it can be difficult, even ex-post, to assess unanimously where costs originate and to whom benefits accrue. As a result, this part of the inter-TSO compensation mechanism was capped at a monetary threshold low enough for the involved parties to agree on–yet likely too low to do justice even to the current investments, let alone the significantly higher investments expected in the future. Congestion revenues, in principle, should serve as a motivation for investments for TSOs. To prevent TSOs from artificially creating congestion, EU network regulation ensures that congestion revenues do not increase the TSO's profits and directs their use towards specific purposes such as increasing network capacity.[17]

Finally, the combination of many different mechanisms, including the combination of ex-ante and ex-post settlements, bears challenges regarding double-counting or reliability, and predictability. With a variety of mechanisms, the same benefits might be compensated for in the CBA and accrue again later as congestion revenue. Similarly, a positive settlement from the CBA may be (partially) reversed for a specific Member State, via the loss settlements in the inter-TSO compensation mechanism. Thus, for the challenges ahead, a holistic and seamless system of cost-sharing for cross-border infrastructures would be desirable. Yet, an overhaul of all involved mechanisms, including heterogeneous national frameworks, seems unrealistic, especially in the short term.[18]

An important challenge is that interconnection with non-EU countries such as the UK and Norway has proven to be interesting, but more difficult from a legal and regulatory perspective than between EU Member States. The situation, as well as the legal challenges, are different for Norway and the UK.

[16] The Dutch peak power demand is currently 18GW. By 2050, the Netherlands plans to build 70GW of offshore capacity.

[17] Those restrictions were lifted by the European Commission during the energy crisis, to allow the revenue to be used to soften the impact of the crisis for end-users.

[18] Hogan (2018) highlights that costs should be allocated roughly commensurate with the estimated benefits. Given the complexity of the issue, he stresses that the cost-allocation method must be practical rather than aiming for an unrealistic level of perfection.

Norway is part of the European Economic Area (EEA) and as such part of the internal energy market. However, EU legislation is not automatically applicable to Norway. First of all, some topics are fully excluded from the cooperation, which is why the Maritime Spatial Planning Directive, relevant for the planning of offshore wind resources, is not at all transposed in Norway. For the parts of EU legislation that are considered to be EEA relevant, such as the Directives and Regulations related to electricity markets, a legislative lag can be discerned: it has to be decided by the EEA countries together with the European External Action Service whether EU legislation is adopted in the EEA Agreement (integrally or partially), after which it still needs to be transposed in national law. This means that important legislation that is applicable to EU Member States is not, or not yet, applicable to Norway. In January 2025, the Norwegian government fell over adoption in the EEA of the Fourth Energy Package (European Commission, 2019), which means that between Norway and the EU, the 2009 package is still applicable.

For the UK, the current framework governing energy trade with the EU is the Trade and Cooperation Agreement. However, this agreement is temporary, as it is set to expire in June 2026. Experts stressed the urgency of clarifying what the situation will be after this date, noting that the current approach to market coupling leads to inefficiencies, with available capacities being priced too high or too low, and with counterintuitive flows from time to time (Goldberg, 2023).

An opportunity within the existing regulatory framework can be found in Art. 15 of the revised TEN-E Regulation, establishing an obligation to develop guidance on cross-border cost-sharing for offshore grids (European Union, 2022b). This shows that Member States are committed to tackling this issue and are willing to have it developed by a central authority. However, a Guidance document by the European Commission is not binding in nature. Similarly, the TEN-E Regulation prescribes that project developers present an adequate CBA and include a request for cross-border cost allocation. This also shows the acceptance to address cross-border cost and benefit differences and the compensation thereof. However, here, as well, there are no binding rules on this. Moreover, as discussed in the Regulation, the current methods and requirements for both CBA and CBCA should be adjusted to function well. From a legal point of view, methodologies for CBA and CBCA do not have to be laid down in the Regulation itself, but can be part of other documents, which makes them easier to change within a shorter timeframe. On the other hand, the adaptability of the methodologies for CBA and CBCA also reduces legal and investment certainty for project developers.

2.3.2. Policy Options on the Table

The current debate focusses on offshore grids and hybrid infrastructures that include generation investments.[19] ENTSO-E's ONDP outlines that grid connections of future offshore wind farms will increasingly be hybrid (ENTSO-E, 2024b).

[19] See also the CERRE (2024) report on offshore wind for a discussion of some of those elements.

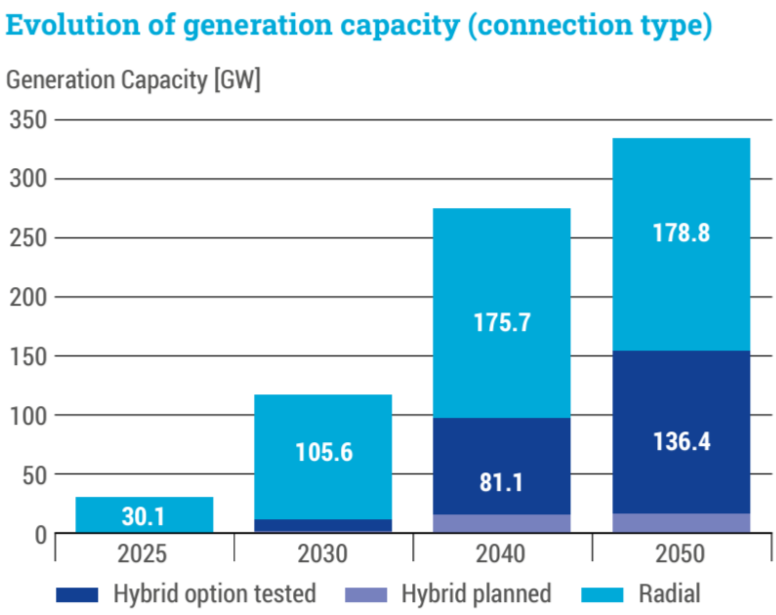


Figure 1: Evolution of generation capacity by connector type

Source: ENTSO-E. (2024b). Offshore Network Development Plans, European Offshore Network Transmission Infrastructure Needs—Pan-European Summary.

It also lists hybrid projects currently under development, such as the North Sea Wind Power Hub, the Energy Island Bornholm, Triton link, Lionlink and Nautilus. Several of these projects are currently stalled or struggling for a viable investment framework for generation in combination with cost-sharing agreements for grid infrastructure.

In 2024, the European Commission issued a Guidance for a collaborative investment framework for offshore energy projects, addressing issues such as underlying scenarios, counterfactuals, bidding zone configuration and systemic complexities like onshore reinforcements (European Commission, 2024). It also encourages exploring new cost-sharing approaches such as:

- creative sharing of congestion income (beyond 50-50 or ownership),
- bundling of projects (netting cost and benefits),
- ex-post corrections (congestion income sharing key or triggered transfers),
- joint ownership, regional regulatory asset base (RAB), regional planning,
- congestion income to feed regional savings accounts (instead of lowering domestic network tariffs),
- provision of competitive financing conditions by the European Investment Bank (EIB), and
- compensation of net negative benefits via CEF.

This guidance is expected to be translated into a methodology and executed in a first assessment by ENTSO-E throughout 2025.

In parallel, and reflected in these suggestions, several studies have taken up issues related to these infrastructures. Several reports discuss options for support and subsidies for the offshore generation infrastructure, including Contracts for Differences (CfDs), Power Purchase Agreements (PPAs), guarantees and transmission rights (Elia Group & Ørsted, 2024; TenneT, 2024). This is motivated by the need to alleviate the extraordinary risk of developing offshore wind generation when the transmission infrastructure is not yet in place and its layout and the resulting access to the adjacent markets are still uncertain. These stakeholders also discuss the configuration of offshore bidding zones. On the one hand, this also influences the economic feasibility for generators, but beyond that, the zone layout determines congestion rents for the involved project developers and informs the level of costly system operation required, such as redispatch and balancing capacities.

Another issue in the debate is the establishment of some sort of joint governing institution to streamline the planning processes, possibly bundling assessments of various infrastructures regionally and over time, and potentially also administering financing support or even providing funding. With varying mandates, such an institution is referred to as an Offshore Investment Bank (Elia Group & Ørsted, 2024), Offshore Financing Facility[20] or Offshore Joint Venture (Sen et al., 2014). Beyond support and governance, the current debate also includes streamlining timelines and the planning and permitting processes for hybrid infrastructures connecting grids and generation, in order to reduce the risks arising from their interdependence.

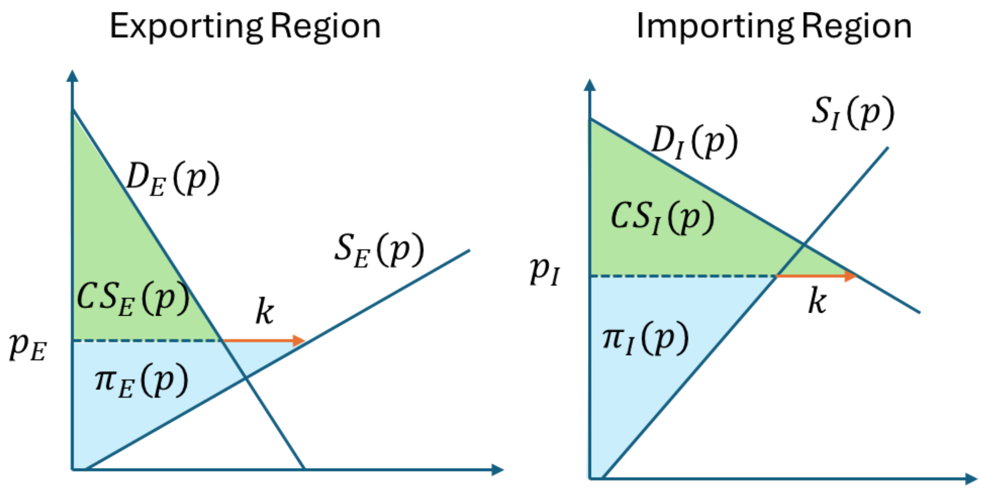
[20] See: North Seas Energy Cooperation (NSEC).

3. Conceptual Framework

3.1. Transmission and Strategic Trade effect

This section describes the market value of an interconnector and corresponds to the first benefit indicators under the CBA. We illustrate how an increase in the interconnector size will have offsetting effects for consumers and producers in importing and exporting regions and how it changes the congestion revenues for the system operator. We will then discuss possible cost allocations in which countries will never veto socially optimal investment decisions and allocations that share net surplus equally.

Figure 2: Effect of an Interconnection on an Importing and Exporting Region



Price Effects

We first study how the interconnector affects prices in the importing and exporting regions. Those price effects determine in the end the winners and losers of the expansion of network capacity. An expansion will increase the price in the exporting region and decrease the price in the importing region. The price effect will be larger, the larger the slope of the aggregate net supply curve $S' + |D'|$. This is a measure of how much a region's price responds to imports or exports.

$$\text{Exporters: } \frac{dp_E}{dk} = \frac{1}{S'_E + |D'_E|} > 0, \qquad \text{Importers: } \frac{dp_I}{dk} = \frac{1}{S'_I + |D'_I|} < 0.$$

Effect on Network Users

Producers in the exporting region and consumers in the importing region gain, while the consumers in the exporting region and the producers in the importing region lose. The marginal effect of an expansion for the different network users is proportional to the price effect given by:

$$\text{Exporters: } \frac{dCS_E}{dk} = -D_E \frac{dp_E}{dk} < 0 \;\; \& \;\; \frac{d\pi_E}{dk} = S_E \frac{dp_E}{dk} > 0\,,$$

$$\text{Importers: } \frac{dCS_I}{dk} = -D_I \frac{dp_I}{dk} > 0 \;\&\; \frac{d\pi_I}{dk} = S_I \frac{dp_I}{dk} < 0.$$

In each region, there are winners and losers from changing the interconnector size, but will in the aggregate, network users gain from an increase in transmission capacity? A standard result from trade literature is that both regions will gain from reducing trade barriers. This result holds here as well. In the exporting region, the producers gain more than the consumers lose; in the importing region consumers gain more than the producers lose. The intuition is the following. The welfare effect of a price change for domestic transactions is zero as the consumers' and producers' effects offset each other. However, the price effects matter for imports and exports. With more interconnection capacity, the exporting regions export at a higher price p_E and the importing region imports at a lower price p_I. So, both countries gain from extra interconnection capacity.

$$\text{Exporters: } \frac{dCS_E}{dk} + \frac{d\pi_E}{dk} = k\frac{dp_E}{dk} > 0$$

$$\text{Importers: } \frac{dCS_I}{dk} + \frac{d\pi_I}{dk} = -k\frac{dp_I}{dk} > 0$$

Will both countries benefit to the same extent from an increase in transmission capacity? The two expressions show that countries whose wholesale prices respond more to the increase in transmission capacity will benefit more than countries where the wholesale price does not respond to the increase in transmission capacity.

We will illustrate this with an example in Figure 3. Consider an exporting country which has a lot of natural resources with many high-quality locations for new RES capacity. In the long run, the exporting country's wholesale price will not respond much to an increase in exporting abilities, so dp_E/dk is small. The benefits from increasing trade are therefore small for its network users. An importing country which has only limited suitable locations for new RES might respond a lot to additional import capacity. The welfare gains from trade might therefore be larger.

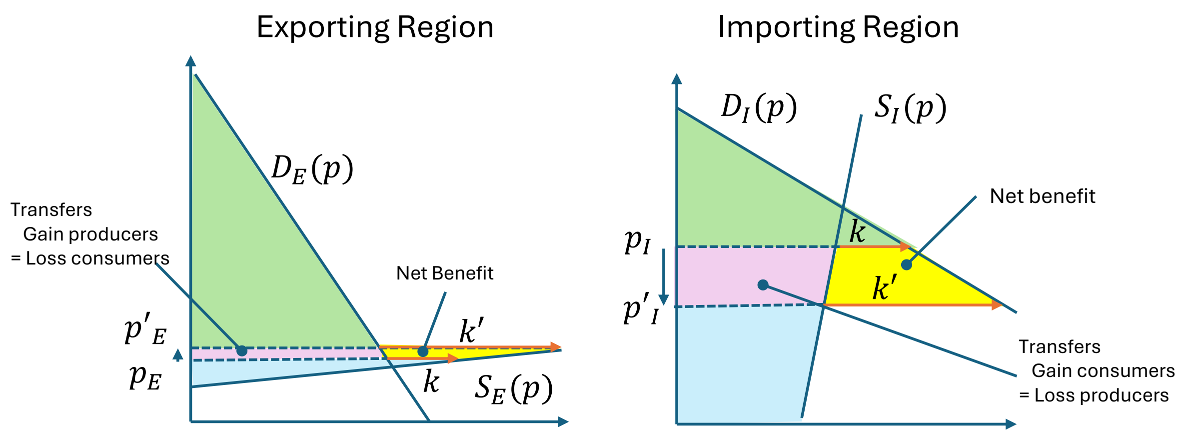


Figure 3: Impact of an increase of transmission capacity on a resource-rich exporting country.

Note: An increase in transmission capacity from k to k', increases prices in the exporting area and reduces the price in the importing area. Both the exporting and importing regions benefit from the increased trade, but with a flat exporting supply function, the importing region gains the most.

Effect for the TSO

We now turn to the effects of the increase in interconnection capacity for the TSO. The effect of increasing transmission capacity for the TSO consists of three components.

$$\frac{d\pi_{TSO}}{dk} = (p_I - p_E) + k\underbrace{\left(\frac{dp_I}{dk} - \frac{dp_E}{dk}\right)}_{<0} - c$$

The additional transmission capacity allows the TSO to sell more transmission services, whose value is equal to the price difference between the importing and exporting zone $p_I - p_E$. However, additional capacity reduces the price difference and therefore reduces the value of the existing transmission capacity. This reduces the revenue of the Transmission System Operator. A third component is the additional investment costs c that the TSO incurs.

Social Welfare Effect

The marginal effect on the overall welfare of an increase in transmission capacity is the sum of the impacts of all parties involved: network users in the importing country, the exporting country and the transmission system operator. Summing up those welfare effects, we see that it is equal to:

$$\frac{dWelfare}{dk} = (p_I - p_E) - c$$

Increasing the transmission capacity k is socially welfare-improving if the expected congestion price on the interconnector $p_I - p_E$ is larger than the marginal network investment cost c. The marginal social value that is created by expanding the network can be measured by the regional price difference.

When comparing the social effects of transmission capacity with the marginal effect on profit for the TSO, it is clear that the incentives of an unregulated TSO are to exercise market power and underinvest in network capacity to increase the scarcity premium. This is a well-known insight, and EU regulation therefore requires that TSOs perform an objective and transparent network planning and reserve congestion revenue to build new capacity or to lower network tariffs. Hence, the network users could benefit from the congestion rents in the form of lower network charges.

National Surplus

Assuming that the congestion revenue is shared 50/50 between the countries, and that upgrade costs are shared according to the territoriality principle, where the exporting TSO and importing TSO pay c_E and c_I respectively with $c = c_I + c_E$, then the surplus for the exporting region is given by:

$$\frac{dW_E}{dk} = \frac{1}{2}(p_I - p_E) - c_E + \underbrace{\frac{k}{2}\left(\frac{dp_I}{dk} + \frac{dp_E}{dk}\right)}_{\lesseqgtr 0}$$

The effect for the exporting country consists of three elements. The first term represents half the social value of the network capacity. The second term is the national network cost, and the third term combines the two price effects and can either be positive or negative: exports increase the surplus for network users (positive effect) but reduce the value of the existing interconnector capacity (negative effect). In the example presented above we looked at an exporting country with a lot of cheap RES production locations, the third term is negative. The benefits for domestic producers of more transmission capacity are small, as new investments in new RES will keep prices low in the exporting zone. However, increasing capacity will reduce the congestion rents, as the price in the importing region will drop. The exporting TSO captures half of those congestion rents. This expression could explain why Norway might be reluctant to build additional transmission capacity under the territoriality principle.[21]

For the importing region, we have a similar expression, but with the opposite sign for the adjustment term:

$$\frac{dW_I}{dk} = \frac{1}{2}(p_I - p_E) - c_I - \frac{k}{2}\left(\frac{dp_I}{dk} + \frac{dp_E}{dk}\right)$$

The sum of both expressions gives us the total social surplus.

$$\frac{dW_I}{dk} + \frac{dW_E}{dk} = p_I - p_E - c$$

Table 3 provides a numerical example in which the exporting country obtains 17% of the benefits from extra trade, and the importing region receives 83%. The exporting region incurs twice the investment costs ($c_E = 4$) as the importing region ($c_I = 2$). Prices in the exporting region increase by less than the amount they decrease in the importing region.

Table 3: Numerical example of strategic effects of network capacity.

Importing region	$p_I = 50 \quad \frac{dp_I}{dk} = -3 \quad c_I = 2$
Exporting region	$p_E = 35 \quad \frac{dp_E}{dk} = 1 \quad c_E = 4$
Transmission capacity	$k = 5$
Benefit Importing region	$\frac{1}{2}(p_I - p_E) - \frac{k}{2}\left(\frac{dp_I}{dk} + \frac{dp_E}{dk}\right) = 12.5\ (83\%)$
Benefit Exporting region	$\frac{1}{2}(p_I - p_E) + \frac{k}{2}\left(\frac{dp_I}{dk} + \frac{dp_E}{dk}\right) = 2.5\ (17\%)$
Total investment cost	$c_I + c_E = 6$

[21] In this analysis, Norway would have a smaller net benefit because prices in Norway would not rise enough for the exporters to capture the social value of increased exports. Current opposition against network expansion in driven by consumer backlash against network higher electricity prices in Norway.

The total benefit generation by the network is 15, while the total expansion cost is 6, so the social welfare increases by 9 units. If costs are allocated according to the territoriality principle, the exporting region will veto the network expansion as the benefits (2.5) do not outweigh the costs (4).

3.2. Sharing Costs and Benefits

This section examines potential cost-sharing rules for allocating interconnector construction costs, considering future and uncertain benefits. As discussed in Section 2.2.2, these benefits extend beyond trade effects to encompass broader socio-economic welfare impacts evaluated in the TYNDP process, such as security of supply and renewable energy integration.

Equal Surplus Sharing

In order for national regulators not to veto societally optimal investment projects, we need to set the cost-sharing rule such that the 'strategic' long-term price effects (that is, the third term in the welfare expressions) are taken into account. We can allocate the cost shares such that both TSOs obtain half of the total surplus that is generated by the network capacity:

$$c_E^{Surplus} = \frac{c_E + c_I}{2} + \frac{k}{2}\left(\frac{dp_I}{dk} + \frac{dp_E}{dk}\right)$$

$$c_I^{Surplus} = \frac{c_E + c_I}{2} - \frac{k}{2}\left(\frac{dp_I}{dk} + \frac{dp_E}{dk}\right)$$

With those cost-sharing agreements, national incentives are aligned with the socially optimal incentives. Member states each pay half of the investment costs (first term in the expression), with an adjustment term (second term) which depends on the long-term price effects. The country with the largest price effect will have to pay a larger share of the costs. In our numerical example, the importing region pays the full investment cost of the project (6 units) and pays a subsidy to the exporting region of 2 units (See Column 2 in Table 4).

With this rule, each country receives half the social benefits that are created by the network expansion.

$$\frac{dW_I^{Surplus}}{dk} = \frac{dW_E^{Surplus}}{dk} = \frac{p_I - p_E - c}{2}$$

and Member States will only veto projects that reduce social welfare. In our example, each Member State receives half of the social benefits of the network extension (4.5) as illustrated in Table 4.

Table 4: Strategic effects of network operator: territoriality, equal surplus sharing and sharing proportional to benefits.

	Territoriality Principle	Equal Surplus	Proportional to benefit	Equal Cost
Marginal Surplus Importer	10.5	4.5	7.5	9.5
Marginal Surplus Exporter	-1.5	4.5	1.5	-0.5
Cost paid by importer c_I	2	8	5	3
Cost paid by exporter c_E	4	-2	1	3

Cost-Sharing Proportional to Benefits

Assuming that there is a strictly positive net social surplus ($p_I - p_E > c$), then there is a range of cost allocations for which the national governments agree to socially optimal investment decisions. One such allocation is where we allocate the costs proportional to the national benefit. The proportional cost-sharing rule gives the following expression:

$$c_E^{Benefit} = \frac{c}{2} - \frac{k}{2}\left(\frac{dp_I}{dk} + \frac{dp_E}{dk}\right)\frac{c}{p_I - p_E}$$

$$c_I^{Benefit} = \frac{c}{2} + \frac{k}{2}\left(\frac{dp_I}{dk} + \frac{dp_E}{dk}\right)\frac{c}{p_I - p_E}$$

For our numerical example, this is shown in Table 4. The importing region pays 83% of the expansion cost (5), and the exporting region pays 17% of the cost (1).

In the earlier phase of European market integration (characterised by relatively small interconnection capacity k and a socially valuable project extension $p_I - p_E \gg c$), cost-sharing allocation proportional to benefits is approximately equal to equal cost-sharing ($c_E^{Benefit} = c_I^{Benefit} \approx \frac{c}{2}$). This could explain why 50-50 cost-sharing has often been selected in the past.

In more integrated markets, where sufficient expansion projects have been undertaken until the socially optimal level of interconnection is almost reached, $p_I - p_E \approx c$ and where strategic trade effects become more important; the proportional-to-benefits cost-sharing rule converges to the proportional-to-surplus sharing rule indicated above ($c_E^{Benefit} \to c_E^{Surplus}$).

3.3. The optimal Cross-border Project

In this section, we examine the allocation of costs and benefits using a simple example. Consider two countries, A and B, that have the option to invest in two cross-border projects, 1 and 2. Table 5 presents a numerical illustration of the benefits, costs, and net benefits for each country under the territoriality principle, where each country covers the costs incurred within its borders. In this

Table 5: Allocation based on the territoriality principle.

	Territoriality principle						
	Country A			**Country B**			**Total**
	Benefit	**Cost**	**Net**	**Benefit**	**Cost**	**Net**	**Net**
Project 1	120	20	100	50	82	-32	68
Project 2	50	20	30	80	58	22	52

Table 6: Allocations based on equal cost-sharing, proportional to benefits and bargaining power.

	Equal cost-sharing						
	Country A			**Country B**			**Total**
	Benefit	**Cost**	**Net**	**Benefit**	**Cost**	**Net**	**Net**
Project 1	120	51	69	50	51	-1	68
Project 2	50	39	11	100	39	61	72
	Cost allocation proportional to benefits						
	Country A			**Country B**			**Total**
	Benefit	**Cost**	**Net**	**Benefit**	**Cost**	**Net**	**Net**
Project 1	120	72	48	50	30	20	68
Project 2	50	30	20	80	48	32	52
	Cost allocation such that countries share net benefits equally						
	Country A			**Country B**			**Total**
	Benefit	**Cost**	**Net**	**Benefit**	**Cost**	**Net**	**Net**
Project 1	120	86	34	50	16	34	68
Project 2	50	24	26	80	54	26	52

example, project 1 would maximise the total surplus. However, without a cost-sharing agreement, country B would veto the project, leaving only project 2 as a viable option. Thus, cost-sharing agreements may be essential to implementing projects that maximise overall welfare.

Table 6 gives the outcome considering the three distinct cost-sharing mechanisms described above.[22] Under the *equal cost-sharing agreement*, the total cost of a project is split equally between the two countries. For instance, in project 1, where the total cost is 102, each country would pay 51. However, country B would still veto project 1 as it incurs a negative net surplus of -1. In contrast, for project 2, neither country would veto the project, making it a feasible option under this cost-sharing model.

In the *proportional cost allocation model*, each country's share of the total cost corresponds to the fraction of the total benefits it receives. Under this scheme, neither country would veto either project. However, disagreement arises regarding which project to implement—country B prefers project 2, while country A favours project 1.

It is important to note that in this allocation model, costs and benefits are treated differently, which raises several concerns. First, the distinction between a cost reduction and a benefit increase is somewhat arbitrary, making it unclear how certain financial impacts should be classified. Should the costs be shared between countries include only network investment costs, or should they also account for other expenses, such as increased balancing costs, or should balancing costs be treated as negative benefits? Second, if balancing costs are counted as negative benefits, this could lead to negative total benefits, causing the allocation model to break down. Third, the different treatment of benefits and costs may create opportunities for strategic behaviour, where countries could manipulate classifications to influence cost-sharing outcomes in their favour.

In the net benefit equalisation model, costs are allocated such that both countries receive the same net benefit. For project 1, both countries end up with a net benefit of 34, while for project 2, they each receive 26. Since project 1 offers a higher net benefit to both parties, it would be unanimously approved, and no project would be vetoed.

Konstantelos et al. (2017) investigate how the proportional allocation rule can be applied to countries negatively affected by a project. The authors compare two allocation rules for three different North Sea offshore grid projects. The first rule ensures that both host and third-party countries contribute when they benefit from a project and receive compensation when they are negatively affected. The second rule limits financial compensation to host countries only.[23] While the second rule simplifies the process, the authors show that contributions from third-party countries may be necessary to make the project implementable. Sharing the net benefits equally between all countries involved might have some nice properties (such as all countries voting for the socially optimal outcome and treating costs

[22] *Equal cost-sharing* requires each country to contribute equally, with both parties paying half of the total costs. *Proportional cost allocation* distributes costs in proportion to the benefits each country receives from the transmission project. *Equal net benefit allocation* ensures that each country receives an equal share of the net benefits generated by the project, based on the premise that both countries possess veto power and thus have equal bargaining power in the decision-making process.

[23] Olmos et al. (2018) argue that third-party countries that are negatively affected by a new transmission line should not be compensated. These losses are the result of increased competition in the power market and countries should not be protected from that. Note however, that in a perfectly competitive model, increasing trade opportunities will increase overall surplus, and hence the profit losses for generators in the importing country should be outweighed by the gains in consumer surplus.

and benefits in a transparent way) but is too simplistic. The allocation of benefits and costs does not depend on the significance of each country's role in the investment or its corresponding bargaining power. Each country's weight is assumed to be equal. Hypothetically, a third country, C, which is not involved in the project at all, could claim an equal share of the benefits. Equal distribution of the net surplus of the project would give each country a net surplus of 68/3. This is not realistic; it would mean granting Luxembourg a-third of the surplus created by a new transmission line between Germany and Norway.

The Share of Surplus

Let φ_i represent the share of the total net surplus that country i receives in the cooperation

$$\varphi_i = \frac{B_i - C_i}{\sum_i (B_i - C_i)}.$$

Table 7 presents the share of the total surplus that country A receives for both projects under the last two allocation rules.

When allocating the costs proportional to the benefits, it can be easily shown that each country receives a fraction of the total net surplus which corresponds to its relative contribution to total surplus. That is

$$\varphi_i = \frac{B_i}{\sum_i B_i}.$$

The share that country A receives will depend on the project, as shown in Table 7. his explains why countries may disagree on which project is optimal—they might prefer a larger share of a suboptimal project than a smaller share of a project that maximises total surplus. Allocating surplus proportional to the relative size of the benefits has as advantage of reflecting the relative importance of a project for each country. When sharing the surplus equally, each country receives the same share of the total surplus.

$$\varphi_i = \frac{1}{N}.$$

Since this allocation is independent of the specific project, countries agree on which project to choose. However, it may fail to reflect the relative importance and veto power of the countries involved.

Table 7: Country A's share in total surplus φ_A .

Country A's share of total surplus φ_A	Allocating costs proportional to benefits	Allocating costs based on bargaining power
Project 1	71%	50%
Project 2	38%	50%

In the next section, we explore how cooperative game theory can help define these shares more effectively.

3.4. Sharing Rules Based on Cooperative Game Theory

Cooperative game theory is a subfield of economics that studies cooperation among a group of players. It assesses, among other things, whether players will agree to form a grand coalition—an outcome where all players collaborate, and each player finds it in their best personal interest to participate—and how to allocate the costs and benefits within these coalitions according to some given fairness criteria.

Formally, a cooperative game for a set of players N is defined by the characteristic function $v(S)$, which describes the aggregate payoff that any subset of players $S \subseteq N$ can achieve if they optimise their joint coalition surplus. Several methods have been developed to fairly allocate these payoffs, including the core, the nucleolus, and the Shapley value.

Kristiansen et al. (2018) propose using the Shapley value to allocate the costs and benefits of investments in regional offshore grids to countries. The Shapley value assigns each country a share of the total surplus of the grand coalition, reflecting its role and bargaining power. The Shapley value φ_i for country i is calculated as a weighted sum of the marginal contribution of country i to all possible coalitions in which it could participate:

$$\varphi_i = \sum_{S \subseteq N \setminus \{i\}} \frac{|S|!\,(|N| - |S| - 1)!}{|N|!} [v(S \cup \{i\}) - v(S)]$$

In this formula, the symbol $|\cdot|$ represents the cardinality of a coalition, that is the number of countries in the set, and $v(S \cup i) - v(S)$ expresses the marginal contribution of a country i to the coalition S. This represents the extra value created by including country i in the coalition that already contains the countries in set S.

We illustrate Kristiansen et al.'s approach with a simple example. Consider three countries: A, B, and C. Transmission investments can be made between countries A and B, and between countries B and C. However, no direct infrastructure can be placed between A and C. The total welfare gains associated with these transmission investments are presented in Table 8. The table shows that these investments are complementary—investing in both transmission lines yields a higher surplus than the sum of individual investments.

Table 8: Investment projects and pay-offs.

Investment project	Welfare gain
No transmission investments	0
Only a link between A and B	6
Only a link between B and C	6
Links between A and B, and between B and C	18

To use the cooperative game theory approach, we need to transform the pay-off structure at the investment level (presented in Table 8) into a pay-off at the coalition level S and then calculate the marginal contribution of each country to all possible coalitions. This is illustrated in Table 9. Kristiansen et al. assume that a transmission line can only be built if the countries at both its start and end are part of a coalition. They also simplify the model by assuming that countries outside the coalition are not affected by new transmission lines. However, in practice, this is not the case, as new transmission lines influence power prices and may alter network flows and congestion patterns. For this approach to be valid, these effects on third countries must either be negligible, or those countries must be fully compensated by coalition members.

Table 9: Marginal contribution of country A.

$S \subseteq N \setminus \{A\}$	$v(S)$	$v(S \cup A)$	Marginal Contribution	Weight
$\{\}$	0	0	0	1/3
$\{B\}$	0	6	6	1/6
$\{C\}$	0	0	0	1/6
$\{B, C\}$	6	18	12	1/3

The Shapley value is then computed by averaging these contributions across all possible coalition formations, applying the appropriate weights. Using the same procedure for countries B and C yields the Shapley values in Table 10. Country B receives the largest share of the benefits as it plays a pivotal role in both transmission lines.

Table 10: Allocation of surplus to the countries.

Country	Shapley value	Share of Surplus
A	5	28%
B	8	44%
C	5	28%
Total	18	100%

The Shapley value satisfies several important fairness properties. First, it is *efficient*, meaning that the total value created by the grand coalition (18) is fully distributed among all players. Second, it is *symmetric*, ensuring that if two players contribute equally to every possible coalition, they receive the same payoff. Here, countries A and C receive the same value of 5. Third, the order in which the projects are built does not affect the allocation. The reason for this is that the formula of the Shapley value can be interpreted as the average contribution of a country across all possible orderings of investments. Finally, if a player does not contribute to any coalition, they receive nothing.

Kristiansen et al., assume that including third-party countries in the coalition does not impact the characteristic function. Their characteristic function represents the sum of the net benefits of all North Sea countries, both hosting and non-hosting, rather than the net benefits of the coalition members only. The payoff, therefore, depends solely on whether a transmission line is built or not. That is, whether the hosting countries are part of the coalition or not. Non-hosting countries do not affect the investment decisions and are not awarded a share of the welfare gains.

Assume that Germany benefits from a new transmission line between Great Britain and Belgium. Kristiansen et al. implicitly assume that Germany would compensate the hosting countries for these benefits, allowing the {GB, Belgium} coalition to capture the full social surplus of {GB, Belgium, Germany}. However, in practice, Germany could free-ride on the investments made by Great Britain and Belgium.

A more common approach, as demonstrated by Nylund (2014), is to define the characteristic function as the sum of the net benefits of the coalition members only. Nylund compares two cooperative game theory methods, the Shapley value and the Talmud rule[24], with simpler allocation principles, such as the equal share principle and a proportional rule.

Kristiansen et al.'s paper demonstrates the usefulness of cooperative game theory and the Shapley value in allocating costs and benefits of network investments. Due to its formalistic nature, this

[24] The Talmud rule, as described in Aumann and Maschler (1985), is a method for dividing the payoff of the grand coalition into a multistep process. Initially, each player receives half of the net benefit of the player with the smallest net benefit. Then, the remaining payoff is divided equally among the players until each one has received half of the net benefit of the player with the second smallest net benefit. This process continues until the entire payoff is completely distributed among the players.

approach requires us to consider multiple projects simultaneously and define the status quo without investments. It also ensures that each country receives a net gain from cooperation, and the approach reflects the natural bargaining position of countries. Further research may be necessary to operationalise this further for the European context.

One of the challenges in the cooperative approach is to translate individual investment scenarios and surplus calculations into the payoff structure for different coalitions. These payoffs will depend on the market rules and European energy regulations. Regardless of whether they are part of a coalition, countries must comply with internal market rules: making existing cross-border capacity available for trade, ensuring sufficient new capacity for cross-border trade, and applying the solidarity principle in investment decisions. These rules will influence their payoffs and bargaining positions.

One concern is the relative bargaining power of peripheral countries versus more centrally located countries, as well as smaller versus larger countries. Peripheral countries may struggle to meet the 15% interconnection goals as they have fewer counterparties to engage with, yet they typically gain more from network connections through increased security of supply and network stability. For larger countries, satisfying interconnection targets may be more challenging if they are defined as a percentage of national consumption. However, they might benefit less from cooperation as they can achieve greater economies of scale internally.

One drawback of the Shapley value is that it does not always lead to a stable allocation of benefits. In the example, where investments are complementary, all countries benefit from joining the grand coalition. However, when investments are substitutes, such as in the case of two competing projects, countries may have an incentive to deviate from the grand coalition and form sub-coalitions if these result in higher welfare gains. Churkin et al. (2019) assess the stability of the Shapley value for a Northeast Asia case study. By analysing the size and the shape of the stable allocation region, they can determine how minor deviations in input data impact the Shapley value's stability.

However, this instability of coalitions is inherent to the existence of substitute investments. It reflects economic and technological realities, and any allocation mechanism may struggle to resolve this issue. Some form of internationally binding regulation (e.g. ACER) and the integration of decisions across other policy domains may be necessary to reach an international agreement.

Investments in transmission capacity create externalities for third countries; hence, the payoffs of those countries will be affected by the formation of coalitions. In Kristiansen et al. those third countries are kept at their reservation utility. There is a growing literature on cooperative games with externalities and alternative allocation concepts to the Shapley value. Determining the characteristic function in games with externalities becomes even more complex, as the coalition payoff will not only depend on the actions and investments taken by countries belonging to a coalition but also on those taken by third countries outside the coalition.

The Shapley value assumes that the total surplus can be freely redistributed through monetary transfers between countries. These transfers might be significant. In cases where countries are risk averse and market outcomes are uncertain, simple monetary transfers might not only be necessary to allocate surplus but also to allocate risk between countries.

4. Case Studies

This section compiles and discusses selected evidence of different approaches to sharing the cost of an interconnection projects between the parties involved. In principle, the agreements can range from a simple rule, for example a 50-50 split (or simpler yet: 100% covered by the main beneficiary), up to a complex agreement based on net benefits over a range of scenarios; potentially even providing for ex-post adjustments corresponding to the realisation of certain scenarios. The goal of this section is to look for interesting case studies that illustrate the existing models and can provide insights for designing future allocation mechanisms, without providing a comprehensive overview of all existing agreements.

Based on the suggestions from stakeholders engaged for this study, documentation from ACER, reports on the PCI process and national publications, we have included examples from the Nordics, Great Britain, France and Germany. We did not encounter cases that deviated a lot from the simple and coarse agreements. Below we look at the main approaches: territoriality, equal split, full socialisation and allocation proportional to benefits.

4.1. Territorial Cost Split

Historically for many interconnections projects the cost have been split according to the territorial principle, meaning that each involved TSO takes on the cost corresponding to the infrastructure built on their territory. This approach is straightforward in a framework where every TSO owns the assets within their supply area and includes them in the regulatory asset base for cost recovery. In some Member States, like for example France, national regulation may even require that the national TSO owns and operates all domestic assets and (or) cannot own any assets outside the country.

Table 11 displays three examples from the Nordic Grid Development Plan (2014), which is now seen as a precursory process for the European TYNDP. Despite acknowledging a diverse set of benefits which might be distributed differently between the involved countries the cost split largely follows the territoriality principle.

Essentially, the territoriality principle also applies to domestic reinforcements. Even when they are necessary to enable cross-border flows or bring about international benefits, domestic reinforcements are commonly paid for by the local TSO and recovered from domestic grid users. This was the case for example for a reinforcement within the Finnish transmission grid linked to the Aurora project mentioned in Section 4.4 below. While the overall project cost was split following the perceived benefits, the cost of the domestic reinforcement was allocated entirely to Finland (Swedish Energy Markets Inspectorate, 2020).

Table 11: Examples of cost allocation based on the territoriality principle in the Nordics.

Link Name (capacity, length)	Year	Cited Benefits	Cost split
Nea-Järpströmmen (200-750MW, 100km)	2009	reduce congestion increase security of supply	Norway: €55 million Sweden: €61 million
Southwest Link (1200 MW, 380 + 436 km)	2016	improve reliability increase transfer capacity increase security of supply	Sweden: €527 million Norway: €175 million
Skagerrak IV (600 MW, 245 km)	2014	increase transfer capacity improve reserve power increase competitiveness increase security of supply	Germany: €370 million Norway: €26 million

Source: Fingrid, Landsnet, Svenska Kraftnät, Statnett, & Energinet. (2014). Nordic Grid Development Plan.

4.2. Equal Cost Split

While the territorial principle is straightforward in the existing regulatory framework, it still requires design choices on where assets should be located. Different geographical routes for cross-border links might affect the distribution of costs and might have different environmental impacts. The locations of some assets like phase shifters might also be somewhat arbitrary. An alternative solution therefore presents itself as a fixed share cost split approach, dividing the cost for example 50-50. A fixed cost split approach allows the parties to look for routes that minimise the total costs of the project. An equal sharing rule might also be appropriate if the main benefits are the reduction of congestion (which will benefit both countries), and where benefits may be hard to measure (e.g. increased security of supply).

An example of a simple 50-50 cost split is the Gulf of Biscay Project between France and Spain in 2017. Although we will later discuss that this project also provides evidence of some other more elaborate cost agreements, at the core the involved TSOs agreed to each assume half of the project cost (CRE & CNMC, 2021), despite the fact that the assets would be located 68% in France and 32% in Spain (PROMOTioN, 2019). In principle, one can also imagine different percentages than 50-50, e.g. a TSO benefitting from an interconnection might take on all of the project cost, in order to realise the project, but we did not encounter practical cases.

4.3. Full Socialisation

Another approach which we often see within Member States, is a harmonisation of tariffs and the socialisation of all network costs. This requires a strong policy alignment and solidarity between parties It means that all fixed costs for transmission infrastructure are recovered from network users without any discrimination for the regional affiliation of the assets or the users. It is sometimes referred to as postage stamp cost recovery. At the European level this would mean pooling all cost for transmission infrastructure in the EU and recovering them indiscriminately from all users of the transmission network (including transfers to distribution grids) according to a predetermined key, such as energy withdrawals or usage peak. This means, implicitly, that investment costs were allocated proportional to the average energy (peak) consumption per connection point at the TSO level. While this can be conceived conceptually, it does not seem readily implementable at the EU level in the foreseeable future.

This type of cost-sharing has been introduced in Germany, where there are four different TSOs, each covering a distinct geographical area. With new wind installations calling for reinforcements mainly in the North of the country, the cost and consequently transmission tariffs rose disproportionately for the two Northern TSOs. Acknowledging that these reinforcements eventually benefit all network users, the legislator decided in 2017 that transmission cost would be pooled and socialised across all German network users (Federal Ministry for Economic Affairs and Climate Action, 2017). Note that high transmission prices in the North, combined with the fact that Germany is (still) a single bidding zone, gives the wrong signals to consumers: they prefer to build new factories in the South, while it would be socially optimal to place load in the North close to the wind farms. While each TSO is awarded a share of the collective revenue corresponding to their asset base and operation, the differences in cost incurred in different network areas do no longer translate into differences in the level of network charges between these areas. The change has been implemented gradually between 2019 and 2023.

4.4. Net-Benefit Sharing

As argued in section 3.2, a cost split based on the expected net benefits of a planned project better aligns the planning and investment incentives of the involved parties. It guarantees that both countries agree to build socially optimal investments and helps them choosing the best project among projects with very different costs and benefits. Two rare examples of explicit consideration of the relative benefits and costs in practice are the Aurora Line between Finland and Sweden and the Gulf of Biscay interconnector between France and Spain.

For the Aurora line[25] the TSOs and regulators on both sides acknowledged that the project would serve to:

- reduce prices in Finland via imports from Sweden,
- balance Finnish variable RES, via Sweden's dispatchable supply and export of surplus to Sweden, and

[25] See: https://ec.europa.eu/assets/cinea/project_fiches/cef/cef_energy/4.10.1-0016-FISE-S-M-18.pdf

- ease maintenance and handling of unexpected outages.

As these benefits seem to accrue mainly on the Finnish side the cost for the project were borne 80% by Finland and only 20% by Sweden (Swedish Energy Markets Inspectorate, 2020).

For the Gulf of Biscay project, the benefits were projected to accrue by 65% to Spain and only 35% to France. Correspondingly, if the French side were to bear more than €525million of the €1750 million overall cost, the project would have presented a negative net present value for France. While, as mentioned above, the agreement stipulated a simple 50-50 cost split, it also included that at least €350 million from the awarded CEF funding should go to the French TSO, reflecting the benefit distribution.

4.5. Cost-Sharing Agreement contingent on EU Funding

The example of the Gulf of Biscay discussed in the previous sections also exhibits evidence of a cost-sharing agreement contingent on EU funding. The agreement between the French and Spanish TSOs had a simple 50-50 cost split as a base line, despite the fact that allocating 50% of the overall project cost to the French side would imply a negative net present value. The TSOs expected to circumvent this by allocating a sufficient share of the expected CEF funding for the project to the French side. It is questionable whether the French TSO could have gone ahead with the project without the EU funding. And the agreement did not include a provision for the contingency that no additional funding would have been awarded; albeit including comparatively detailed provisions addressing cost overruns and maintenance cost (CRE & CNMC, 2021; Swedish Energy Markets Inspectorate, 2020).

5. Conclusions and Policy Recommendations

5.1. Strategic Priorities and Policy Trade-Offs

The EU is at a critical moment in the transformation of its electricity networks to meet net zero targets. The grid is transitioning from primarily bilateral connections to a highly interconnected regional system. This evolution is driven by rising electricity demand and the need to link new wind and solar capacity to consumption centres; by the increasing value of cross-border trade that capitalises on regional differences in renewable resources and storage capacity; and by the spread of multi-purpose projects, for instance, linking offshore wind farms to the grid while also enabling cross-border exchange. System planning remains driven by national transmission system operators, whose plans are integrated through the European Ten-Year Network Development Plan, with ENTSO-E, ACER, and the European Commission providing the common methodology and overarching oversight, and CINEA managing the selection of Projects of Common Interest.

Achieving this ambition hinges on four interlinked challenges: growing investment risk, uneven cost-benefit sharing, regulatory gaps, and the need for greater geopolitical and climate resilience.

1. *Investment complexity and risk challenge.* TSOs now face investments that are not only larger but also far more uncertain, because their value hinges on generation assets that have yet to be built and depend on still-unresolved political decisions. Costly delays in planning, permitting, and construction increase the difficulty, while the growing international scope of grid planning adds another layer of risk.
2. *Cost-benefit allocation challenge.* Traditional bilateral cost-sharing rules (whether based on territoriality or simple fifty-fifty splits) no longer reflect the real distribution of costs and benefits. Countries that are not directly involved in a project may benefit from new interconnectors without contributing to their costs, and today's framework defines benefits too narrowly, focusing on short-term price advantages while overlooking resilience, security of supply and reduced fossil-fuel dependence.
3. *Regulatory and coordination gaps* challenge. A clear disconnect remains between European-level planning exercises and the bilateral negotiations that determine what actually gets built. Incentives are weak for building new generation where it best serves system needs; technologies such as offshore wind and solar require distinct coordination models, and the absence of long-term transmission service contracts leaves investors uncertain about cost recovery.
4. *Geopolitical and climate resilience challenge.* Energy security threats and climate-related shocks, such as High Impact Low Probability Events (HILPs), demand stronger solidarity mechanisms, yet it is still unclear how principles of solidarity should be translated into concrete cross-border investment decisions and financial commitments.

Given these challenges, stakeholders face different trade-offs, which we summarise in Table 12.

Against this background, this report develops policy recommendations.

Table 12: Challenges for different stakeholders: TSOs, EU Member States, transit countries, and EU.

Actor	Trade-offs	Description
Transmission System Operators (TSOs)	Risk & Uncertainty vs. Network Expansion	Must balance high investment risks driven be uncertain demand and political decisions against the urgent need to expand networks for renewable integration.
	National vs. Regional Planning	Face pressure to optimise national networks while also accommodating growing transit flows and regional needs.
	Regulatory Certainty vs. Flexibility	With incentive regulation, demand uncertainty makes TSOs less willing to invest than under rate-of-return rules.
Member States	Cost-Sharing vs. Benefit-Distribution	Must negotiate fair allocation of infrastructure costs while benefits often spill over to non-hosting countries.
	National Sovereignty vs. Regional Coordination	Must balance control over national energy policy with the need for European-level coordination.
	Short-term Costs vs. Long-term Benefits	Face upfront infrastructure costs but reap intangible resilience and energy security gains only in the long term.
Transit countries	Infrastructure Burden vs. Limited Control	Carry an outsized transit flows but have little say in neighbours' decisions.
European Union as a whole	Speed vs. Optimality	Risks "building the wrong assets, too late" due to narrow metrics and slow decision-making.
	Decentralised Flexibility vs. Coordinated Efficiency:	Current bilateral approach allows flexibility but may miss system-wide optimisation.
	Market Integration vs. Infrastructure Readiness	Pushes for market coupling and zero transit fees without ensuring corresponding infrastructure development mechanisms.

5.2. Recommendations

The recommendations address cross-border investment governance, improvements to planning and cost–benefit analysis, risk allocation and mitigation, and enhancements to European financing mechanisms, each of which is discussed in the sections below.

5.2.1. Governance

The current regulatory framework is relatively well suited to bilateral interconnector extensions that address already existing demand for cross-border transmission capacity. However, it may no longer be adequate for new investments that have multilateral effects affecting multiple countries, where benefits are harder to quantify (such as resilience and security of supply) and future capacity demand depends on national energy policies (such as offshore wind and decentralised solar) and future electricity demand (especially large-scale electrification of industrial demand at specific locations).

Given the lack of EU-wide governance proposals and varying regional challenges, we suggest **a layered governance approach**. We propose a model addressing issues at three levels: EU, regional, and bilateral. In particular, governance for projects with large spillovers between Member States should shift to higher levels (EU and regional). This enables regulatory experimentation while respecting subsidiarity principles. Decision-making levels should match project complexity: bilateral projects should be addressed at the national or bilateral level, while multilateral projects with system-wide implications should be managed at the regional or EU level. Table 13 highlights the layered approach of governance as a function of project type.

Relevant issues for the negotiations, to be considered for the initial agreement, may include the energy mix in the relevant Member States (i.e. choice and commitment to supply and demand scenarios), implications from network planning and permitting, the European level cost-benefit assessment, available support and financing, initial cost allocation as well as ex-post settlements that distributed costs or benefits related to the project, such as tariff setting and the split of congestion revenues.

For each of these, the responsible actors at the appropriate governance level should be clearly identified. These may include Transmission System Operators (TSOs), national regulatory authorities, Member States or network users. Section 2.3.2 explores various dimensions of reforming the current governance framework.

The roles of different parties merit careful consideration. Risk should be shifted to the parties that are primarily responsible for creating it. Governments may expect foreign TSOs to make investment decisions shaped by national policies, but they typically drive major network expansion decisions and determine the generation mix and its geographic distribution. They may therefore need to commit to buying long-term transmission corridors; for instance, in the form of long-term transmission rights. Although direct state involvement in long-term transmission rights may appear counterintuitive, when governments purchase financial transmission corridors, risk shifts to the party primarily responsible for creating it through energy mix decisions. Additionally, financial transmission rights serve as a governmental commitment mechanism. Finally, expecting private parties to commit to transmission assets with ten-year development timelines and operational lifespans exceeding forty years is unrealistic.

National and European regulation sometimes hinders the development of novel agreements between national TSOs. We are considering options to facilitate co-ownership of physical assets with other TSOs (possibly outside national jurisdictions) to enable risk-sharing, and to allow TSOs to carry out activities that are not subject to regulation. This is not always allowed by national legislation. Furthermore, allowing TSOs to create long-term financial transmission corridors (longer than 1 year) could be considered, provided that the pro-competitive and sustainability benefits, such as providing certainty for new green investment and enabling international capacity markets, outweigh the potential anti-competitive effects, such as creating opportunities for incumbents to foreclose the market or deter new entrants. Both issues can be tackled by amendments to European and/or national legislation.

The long-term EU-wide interconnection target, which states that interconnection capacity should amount to 15 percent of installed generation capacity, serves as a driver for the development of cross-border infrastructure and provides a reference point in negotiations between Member States. However, the current target should be adjusted or complemented by indicators that are more closely aligned with the objectives of market integration and the economic fundamentals of cross-border electricity trading. For example, the target is currently defined at the Member State level without accounting for the economic impact of congestion on the physical network (both national and cross-border) and its effect on European market integration.

In addition, the current target is based on total installed generation capacity, without accounting for the variability in availability factors across different energy sources. It is therefore not appropriate to treat all generation technologies equally. The geographical location and relative size of a country also influence the feasibility of meeting the target; achieving 15 percent interconnection is considerably easier for smaller countries than for larger ones. Alternative indicators could include a gradual reduction in average price differences between neighbouring trading hubs and resilience-based metrics.

We believe that these interconnection targets are useful in speeding up the negotiation process among Member States, and between Member States and third countries. They provide clear incentives for TSOs and regulatory authorities to collaborate. Another issue with the current targets is that they lack enforcement mechanisms.

Possible tools to stimulate reaching the (revised) targets could be a carrot and stick system with financial rewards or extra contributions to a fund to be used for the development of European energy systems. Alternatively, a system similar to that used for the climate targets (with indicative trajectories and proceedings against member-states that fail to reach the targets) could be used. However, for both options it is important that the targets are amended to reflect current discrepancies, as addressed above.

Table 13: A layered approach for governance levels

Dimension	Current Process	Recommendations: simple, bilateral cases	Recommendations: complex, multi-stakeholder cases
Network planning	• model, consistent with national objectives • ENTSO-E uses an expansion planning model with a simplified network model, consistent with EU-wide objectives. National TSOs develop national planning	• TSOs linking their respective national plans bilaterally. • Binding bilateral commitments, not only concerning grid planning but also related generation infrastructure, such as offshore wind.	• More detailed regional TYNDP models (including internal network constraints) • Alignment of national and regional energy scenarios (e.g. on renewables) • Binding regional commitments, not only concerning grid planning but also related generation infrastructure, such as offshore wind.
Permitting	• Various legislative initiatives to speed up permitting.	• Monitor permitting process improvements and take adequate measures if needed.	
CBA	• Project specific CBA based on TYNDP. • Results are provided by project developers		• As part of the TYNDP: CBA assessment of system needs irrespective of project proposals.
Support and financing	• Financed mainly via network tariffs in the hosting countries • Some contributions via CEF (EU-level) • Congestion revenues provide additional income (ex-post)	• Keep current methodology but consider different sharing rules for costs and congestion than 50/50. • Remove condition of CBCA for CEF funding for studies.	• Augment current methodology with ex-post adjustment rules based on scenario realisation and alignment with regional commitments.
Ex-ante cost allocation	• Simple cost split (50/50 or territoriality principle), • Commitment of cost into the regulatory asset bases of the national TSOs	• Cost split based on net benefits in agreed-upon scenarios • Considering national and EU interests (solidarity principles).	
Ex-post cost allocation	• Transfers via congestion revenues, • Inter-TSO compensation, • National differences in energy related injection charges	• Keep status-quo	• Ex-post adjustments corresponding to the materialisation of agreed upon scenario • Agreement between national governments and
Tariff setting	• Differences in network tariffs (for energy injections) between Member States	• Harmonisation of injection charges • Rely on capacity - based injection charges to steer investment location, instead of energy-based tariff	• Ensure that capacity and connection charges do not distort investment decisions on both sides of the national border. • Part of the network tariffs could be based on solidarity between member-states.

5.2.2. Increasing the coherence of existing planning and CBA

The existing harmonised CBA process for network investments is useful and seems to improve the quality of the decision process. Nevertheless, it can be improved further in the future.

CBA studies use TYNDP scenarios that change biennially. Planning would improve with consistent scenario structures, fewer negotiations, and stronger energy commitments to reduce uncertainty. National TSO assumptions often misalign with European scenarios due to incoherent methodologies or underlying assumptions, creating assessment gaps that current processes do not address. Coherence between European and national scenarios in both approaches and assumptions is essential.

The CBA should be integrated earlier in the TYNDP process and organised centrally rather than on a project-specific basis. Cost-and-benefits assessments could contribute to the development of the TYNDP by identifying system needs. Project developers would then supplement this general system-needs-based CBA with project-specific elements. This approach expands CBA use beyond merely the selection of projects for PCI status and CEF funding.

5.2.3. Lowering risks with explicit agreements

A system where cost-sharing is proportional to ex-post benefits seems equitable, as the country that benefits most also pays the highest cost. In practice, however, there are challenges with this approach, as it could lead to **significant hold-up problems**. For instance, consider a transit country A that increases its transmission capacity to provide offshore wind electricity to country B. However, country B later relies more on natural gas with carbon capture and storage instead and no longer needs to import green wind power. Country B would then benefit less from the transmission capacity and may no longer contribute to the investment costs.

A well-designed agreement should give TSOs the opportunity to **hedge the evolution of generation and demand** in neighbouring countries or insure against the risk that changes in national energy policies in those countries alter generation and demand patterns. The agreement should not only commit Member States to the national generation and demand scenarios, but also to complementary network investments that support the interconnector and form the basis for the ex-ante benefits' assessment. If the future energy mix deviates from the initial scenarios and the infrastructure is not needed (to the same extent) as anticipated, the TSO should receive some compensation. This agreement could also hedge the risk that a lack of planned investments in complementary networks by a foreign TSO would reduce the value of the interconnector. In short, ex-post settlement should mitigate Member States' incentives to manipulate the energy mix to shift costs to their neighbours.

Part of the investment risk is caused by the lack of hard commitments on the energy mix: timing, technology (capacity factor) and location of the energy sources. Within each Member State these commitments can be organised by contracting with private parties and providing some government guarantees. In an international context such a hard commitment may require an international compensation mechanism between Member States in case commitments are delayed or postponed. This compensation mechanism is currently not foreseen in EU energy law, so this would require an additional agreement between member-states on a voluntary basis. Alternatively, if this is going to be incorporated in EU energy law, it needs to be made clear how it fits with Art. 194(2) TFEU, which gives

Member States full sovereignty over their own generation mix. In this light, it is important to note that the sovereignty remains with the Member States, but that commitments made at a certain point bear consequences if they are not met.

Private contracts could be used to formalise the reallocation of risks between network users (or governments on their behalf) in one country and a TSO in another country. One such example could be a financial transmission corridor. A government might commit to buying a *financial transmission corridor* to an offshore wind location. This corridor could take the form of a long-term financial transmission right (FTR) that connects a country to the offshore wind farm and hedges against future congestion rents on the line. The country pays a fixed fee in return for obtaining a fraction of the congestion rents on this corridor. Hence, this corresponds, in essence, to a shift of congestion rents on this corridor to one country in return for compensation spread over the asset's lifetime. By selling an FTR, the TSO obtains more certainty about its revenue but faces execution risks if it is unable to build and provide transmission services on time. For factors outside its responsibility, such as permitting delays, some mutual risk-sharing needs to be foreseen.

Currently, the main mechanism for sharing the risk of varying utilisation rates of interconnectors is the **split of congestion rents**, which gives each TSO a monetary stake in the market value of the interconnector. For almost all interconnectors, this split is on a 50-50 basis. We suggest that future splits of congestion rents follow the ex-ante split of the investment costs, in order to align incentives for investment decisions. So, if the ex-ante cost split is 20-80, the congestion rent split should follow the same 20-80 ratio. The ex-ante cost split should depend on the bargaining power of the countries involved and the long-term benefits they will each receive from improved interconnections.

Rebalancing the **network tariffs** by increasing the energy component of the injection charges in order to make consumers of exported generation pay for part of the network upgrades, might seem like a tempting way to shift cost between Member States. However, it will distort the internal market and interfere with allocation and split of congestion rents. Such charges will distort European competition if the interconnector is not congested, as generators will face different energy tariffs, and reduce the congestion rents if the interconnector is congested, thereby undermining the congestion rent-sharing rule. We therefore favour keeping the energy component for injection low, as is currently the case in most Member States. Increasing the capacity or connection component of injection charges will reallocate network costs within a country but will not affect the distribution of risks and costs between countries.[26] Still, injection-based network tariffs can steer investment decisions to locations for which less network investments would be required. Those tariffs might need some harmonisation in order to provide locational incentives based on the overall network costs, rather than only national ones.

One way to reduce and manage risks related to operational and investment costs is through the creation of an **alliance** to share the risk. This could take the form of a joint venture, shareholding arrangement, or another agreement for developing an interconnector between two (or more) TSOs

[26] This is also confirmed in a formal analysis by Neon & Consentec (2025) for TenneT "Injection charges for cross-border grid cost recovery".

from different Member States. Such an interconnector could be a non-regulated, for-profit entity (a merchant investment), or be subject to regulation by the relevant NRAs or a joint cross-border regulatory committee: this is the case on the island of Ireland, where such decisions are taken by a committee consisting of a representative from each NRA and an independent party.

5.2.4. Improving European financing mechanisms

Currently, the main idea is that cross-border projects pay for themselves: if there is no positive CBA, the project will not go to the next phase. If the costs and benefits are spread unevenly, the CBCA can alleviate this inequality. In specific circumstances, the Connecting Europe Facility (CEF may step in to provide extra support for studies or even works. The CEF is meant to provide funding to increase affordability (e.g. help peripheral countries) and support projects which have wider strategic objectives. They are not meant to deal with projects that are inherently profitable for the parties involved.

Several benefits of cross-border projects are hard to quantify. Security of supply, increase of grid resilience, geopolitical goals, importance for making the European continent less dependent on fossil imports are examples. It may be more difficult to show in the project development phase what exactly the benefits are, and which countries benefit. In this case, funding mechanisms at the EU level should be extended. It is preferable to concentrate funding in one specific entity, such as the CEF, or in one dedicated entity per region (such as an offshore investment bank). This is in line with the principle of increased energy solidarity between the member-states.

Financial support for transmission lines could be provided in the form of **Contracts for Difference (CfDs)**, which are currently being discussed for generation capacity. For transmission lines, such contracts would resemble Financial Transmission Rights (FTRs) by being based on regional price differences. However, CfDs are typically more closely linked to specific assets, in this case transmission lines, and could be tailored to particular transmission profiles to better reflect the expected use of the assets and facilitate targeted project funding. In contrast to energy CfDs, however, there is no scope for allocating transmission CfDs through a competitive auction process, as this concerns a regulated sector with entry barriers.

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