# Cross-border Allocation of Costs and Benefits of Shared Energy Infrastructure in the EU

## An Organisational Perspective

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WORKING PAPER

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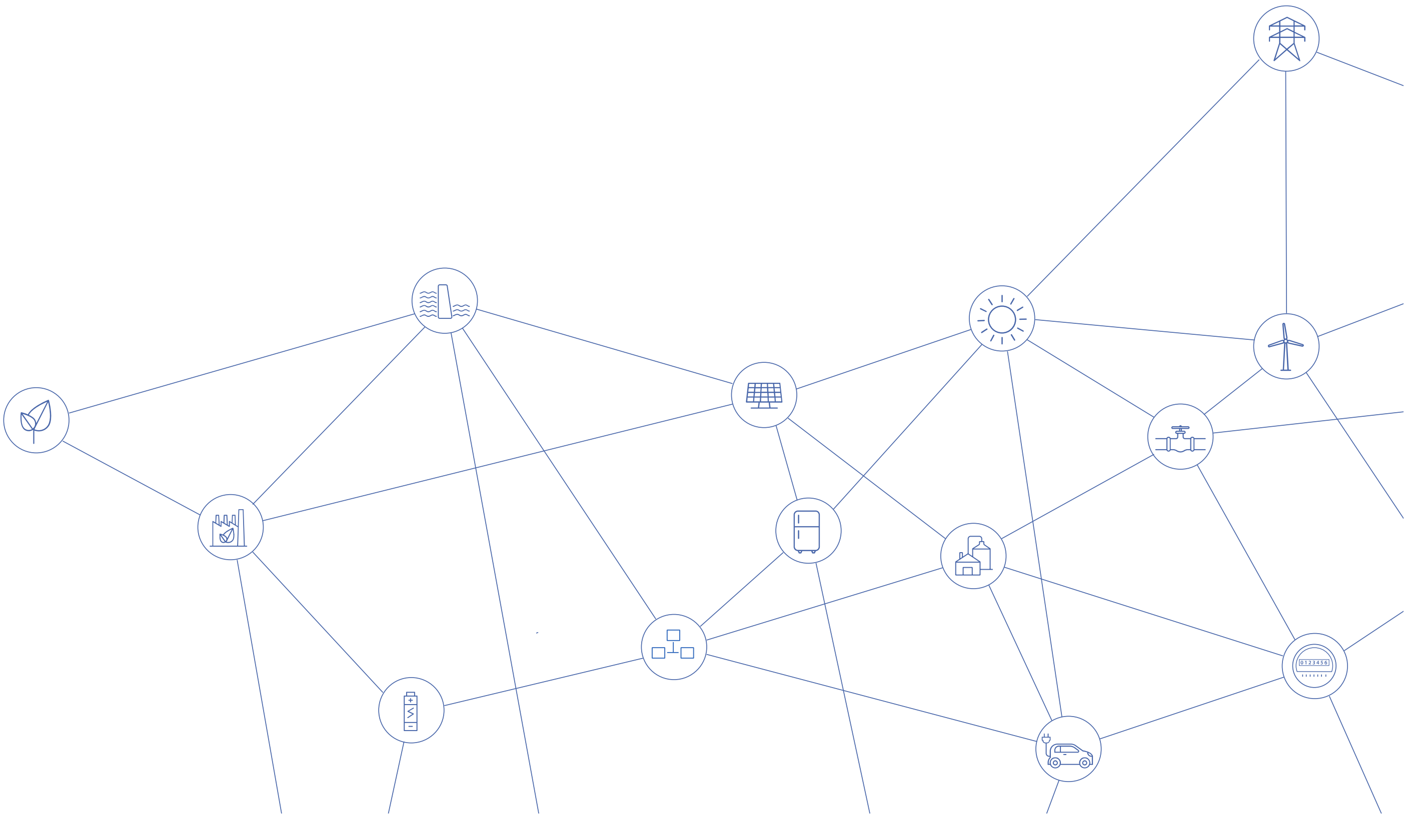

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PREPRINT

# Cross-border allocation of costs and benefits of shared energy infrastructure in the EU: An organisational perspective

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## Abstract

EU electricity infrastructure will need to undergo significant expansion to meet future demand for green energy, as member countries seek to meet their 2050 net zero targets. Meeting these targets requires the development of cross-border transmission networks, as high shares of offshore renewables need to be integrated in energy "hubs" and into mainland markets. However, the current liberalised national, but integrated, energy markets present challenges to the efficient development of the hubs. In the emerging offshore multi-vector renewable system, a simple allocation of the investment costs of a "hub" among its beneficiaries is not necessarily proportionately aligned with the benefits drawn from it. This challenge is exacerbated by the allocation of property rights to operate regulated natural monopolies of national Transmissions System Operators (TSOs), creating a fragmented ownership structure. We propose a solution based on the logic of collective action – namely, that a subset of EU member states have the shared incentive to cooperate on the joint development of assets. We then outline a Joint Venture framework that decouples the decision to invest from the decision on the allocation of costs and benefits across beneficiaries, enabling essential investments to proceed. This model also exhibits favourable dynamic properties for gradual development of hubs.

**Keywords**: Cost allocation, decarbonisation, electricity, networks, climate, energy, security

**JEL Categories:** L50, L51, L94, Q40, Q48,

# 1. Introduction

As EU countries decarbonise their economies to reach net zero by 2050, electricity infrastructure will need to undergo major expansion to meet rising demand (IEA, 2023). In anticipation of this new demand, maturing renewable energy technologies necessitate new industry configurations. The steep reduction in wind and solar costs over the last decade, technological advancements in energy conversion and storage, and the imperative to decarbonise the energy sector require new models of operation for renewables. Offshore renewable energy assets such as "energy islands" or "hubs"– consisting of bundled offshore wind farms, battery storage, and Power-to-X (PtX) facilities – are being developed in the EU, with energy production intended for mainland EU markets.

Collective targets on decarbonisation and emissions reduction, as well as constraints on the optimal siting of resources imply that EU member states have an incentive to cooperate on the development of these assets. The logic of collective action suggests that a subset of members of a group with intensive interests tend to organize themselves to achieve specific common objectives (Newbery, 2019). Economic and security of supply considerations also invoke this logic as a factor in the conception of governance arrangements to coordinate and optimise the use of offshore renewable resources.[1]

Energy produced from offshore renewable systems will need to be transported through new and existing (reinforced) transmission grids, to mainland and cross border electricity markets. The added complexity of new models of shared renewable infrastructure, potentially involving conversions of energy vectors and bidirectional flows, implies that traditional or conventional approaches to the sharing (or allocation) of costs and benefits from these infrastructure investments may not be possible, while at the same time, the logic of collective action suggests the joint development of shared infrastructure.

Any framework for efficient investment would seek to dynamically maximise the expected net present value of total benefits minus total costs. For a given level of projected demand, this would require total costs to be minimised to meet demand; the even broader social cost framework would include various policy instruments to incorporate externalities through regulation (Hogan, 2018). The 'beneficiary-pays' principle envisions cost allocation that is reasonably commensurate with the distribution of benefits (Hogan, 2018).

While there is a net social welfare gain to be had through the development of shared renewable infrastructure, the costs, benefits, and net gain of these can fall unevenly, or be randomly distributed, among beneficiaries and affected parties. This is further complicated by uncertainties and subjectivities in perceptions of how 'benefits' might be defined and evaluated. There may be a perceived (net) social benefit in a shared project going ahead (impacting the decision to build from a societal perspective), but the costs and benefits might

[1] The European Commission has for instance, identified the North Sea Offshore Grid (NSOG) as a strategic energy infrastructure priority.

in practice not be aligned across actors (impacting the decision on how to split the costs). This could in many cases prove an impediment to the project moving forward.

In this paper, we propose a solution to this issue through a Joint Venture (JV) framework that decouples the *decision to invest* from the *decision on allocation of costs and benefits* across the concerned actors, thus enabling essential investments for the energy transition to proceed. Section 2 outlines key challenges in the development of shared grid infrastructure in a rapidly decarbonising system. Section 3 reviews the literature. Section 4 proposes a JV configuration to facilitate the cross-border cost and benefit allocation problem. Section 5 concludes.

## 2. Transmission infrastructure in EU and challenges

Given national and global decarbonisation, renewable targets, and electrification targets, cross-border network infrastructure has gained prominence, especially in countries with shared regulatory jurisdictions in the EU. Cross-border transmission infrastructure planning has always posed challenges, due to the need to achieve agreement around the allocation of costs among the countries involved. An additional challenge arises with the introduction of renewables into cross border energy systems. A third challenge pertains to the role of natural monopolies – Transmission System Operators (TSOs) in the development and operation of the infrastructure.

### 2.1 Cost allocation

International transmission interconnections can be unilaterally vetoed by a country at one end of a proposed project, if it perceives that it will receive an unfairly low fraction of the net economic benefits that result from the project (i.e., net of imports, exports, local changes in electricity prices and carbon emissions, and the allocated portion of congestion rents and investment cost of the transmission line) (Kristiansen et al., 2018). This complexity increases with the number of parties involved. Third-party countries, which are part of the existing interconnected transmission grid but will not host any of the proposed lines, might also be affected by large grid developments elsewhere in the network (Kristiansen et al., 2018).

Ignoring impacts on third-party countries could result in political tension among members of the interconnected system or failure to realise the full benefits of a highly interconnected grid: for e.g., cost-bearing countries could have difficulties in achieving an agreement due to free-riding issues if a third-party country that receives positive net benefits from new transmission projects is not considered in the negotiations (Kristiansen et al., 2018).

On the other hand, a third-party country that is negatively affected by new transmission projects might be able to pose credible threats to the overall system if it does not receive a compensation that is commensurate with its local economic losses (Kristiansen et al, 2018). Finally, failure to achieve an agreement to develop a cost-effective portfolio of transmission investments in the region can also have an impact on the location, size, and type of new investments in generating capacity – potentially rendering investments inefficient (Kristiansen et al., 2018).

### 2.2 Integrating renewable energy

As a rule, transmission charging, and connection arrangements should encourage the least system cost of delivering reliable electricity to end consumers. In vertically integrated markets designed for fossil fuels, the location of generation assets and transmission planning were arguably in greater alignment, keeping total system costs low. In liberalised markets, least-cost transmission can be achieved through a combination of incentive regulation and wholesale market pricing signals (or tariffs) to give the correct signals for locating investment (Newbery, 2023). In the short run the tariffs should encourage the least-cost feasible dispatch of the connected assets – generation and trade over interconnectors (Newbery, 2023).

However, the regulatory mandate for ramping up renewable deployment (e.g., in EU regulation) has meant that large numbers of renewable projects have been located and connected to grids at places which have not been mandated by market price signals. Furthermore, the policy-driven deployment of large amounts of renewables on the grid (e.g., through renewable obligations), without parallel grid reinforcement, has created congestion – leading to costs for consumers and opportunities for producers in undersupplied areas. Investment incentives for renewable generation irrespective of congested network locations, might distort investment efficiency.[2] This exemplifies a key challenge of cross border transmission in a decarbonising energy system.

### 2.3 The role of TSOs

European Transmission System Operators (TSOs) are responsible for the transmission of electricity (usually at voltage levels of 220 kV and 380 kV) and for safeguarding the security of supply in their region, playing a central enabling role in the energy transition (Biancardi et al, 2021). They are the pillars upon which the EU aims to create a single European energy market, for instance, by increasing interconnections between countries and enhancing the reliability of the grid (Biancardi et al, 2021).

TSOs can take a position in international business activities (especially when host countries present low risk and stable political and regulatory frameworks) with the objective of using their expertise to improve foreign country electricity infrastructure, for instance, by building, owning and operating a transmission grid (Biancardi et al, 2021).

As natural monopolies, TSOs operate under a regulatory framework which affects their incentives for investments in infrastructure and operational decisions (Joskow, 2008, 2014; Egert, 2009). TSOs categorize their activities between: (i) asset/infrastructure management; (ii) controlling/operating the electricity system (system operation); and (iii) facilitating the market/developing the EU market (TenneT, 2019; Elia, 2019). TSOs may face significant challenges in public acceptance, due to the 'Not In My Backyard' (NIMBY) syndrome, which

[2] For instance, Newbery (2023) points out how large amounts of policy-driven deployment of wind power in Scotland amplified the profitability of windy locations (mainly in Scotland), overcoming much of the location signalling of the Transmission Network Use of System (TNUoS) tariffs.

may hamper or prevent infrastructure investments (e.g., building new high-voltage overhead lines) and technological innovation (European Commission, 2019).

TSO's activities have been broadly categorised into 'regulated' and 'non-regulated' activities (Di Castelnuovo and Biancardi, 2020). Regulated activities are covered by tariff regulation and relate to the development of new Capex to enable energy transmission, and Opex for the correct functioning of the system (Biancardi et al., 2021). In some cases, TSOs may carry out activities which generate regulated revenues in other regulated businesses (e.g., electricity distribution or coordination with gas networks). 'Non-regulated' activities are instead conducted in a competitive regime (e.g., O&M conducted for third parties, EPC, provision of services to telecommunications operators using own electricity infrastructures and assets, or private interconnectors financed through third parties).

Across the TSOs of 13 European countries (Belgium, Bulgaria, Denmark, France, Germany, Greece, Italy, Netherlands, Portugal, Romania, Spain, Sweden, UK), about 87% of revenues, on average, are generated by domestic regulated activities related with transmission of electricity,7.5% are generated by other activities performed within domestic boundaries (both regulated and non-regulated) and only 6% come from international activities (both regulated and non-regulated), indicating that TSOs tend to avoid activities which are not regulated, thus perceived as risky (Biancardi et al, 2021). In 2018, the share of domestic revenues from transmission of electricity for individual TSOs reportedly varied from 22% for National Grid (UK) up to 100% for TenneT (Netherlands and Germany), ESO (Bulgaria) and Transelectrica (Romania) (Biancardi et al., 2021).

In rapidly decarbonising renewable-based systems, it is increasingly difficult to define the boundaries of the electricity system, as these are extremely porous. For instance, investments made in one part of the system might yield benefits (e.g., lower prices), or indeed, costs (e.g., high congestion) in a completely different part, when the infrastructure is shared across countries with differential energy supply and consumption profiles. Thus, a 'redrawing' of traditional boundaries may be needed to allow new solutions to emerge and to unlock net social benefits of infrastructure investments that may not proceed under traditional methods of cost allocation.

## 3. Literature review

The application of economic method and regulation to the energy sector is more effective when the structure and organisation of the sector is favourable. Moreover, the context since market liberalisation has changed, as decarbonisation and renewable electrification have risen to dominate the policy agendas (Jamasb et al., 2024). Sen and Jamasb (2025) have argued the need for a new offshore governance regime given the significant technological and energy policy developments in recent years.

Existing literature covers both the identification of costs and benefits, and their allocation. Most studies focusing on the cost allocation build on the "beneficiary-pays" principle. Olmos et al. (2018) and Rivier et al. (2013) argue that since the benefits derived from network investments are the main reason for undertaking them, the cost of regulated network investments may be allocated to network users proportionally to the benefits they are expected to draw from it. Further, charging network users the fraction of the grid costs they benefit from should result in efficient grid charges. Olmos et al. (2018) argue that when regulated network investments are undertaken by passive TSOs or independent transmission companies these investments should be remunerated according to their costs, as determined through some kind of competitive process to allocate the construction of these assets. Khezr and Menezes (2019) propose a novel auction-based methodology for provision of services to new beneficiaries from investments in new infrastructure development.

Hogan (2018) outlines three broad cost allocation principles set out by the federal electricity regulator in the United States, requiring that cost causations are “roughly commensurate” with the distribution of benefit. These are: (a) load ratio share across the entire network, (b) proportional share based on each party’s share of total quantified benefit, and (c) cost assigned to zones based on load flow analysis. Of the three, (a) simply reduces to socialisation of costs and benefits, while (c) (flow-based approaches) have been shown to have little or nothing to do with the evaluation of benefits: only (b) reflects a formal consideration of the allocation of benefits.

Olmos et al. (2018) argue that when an active TSO decides over the construction of regulated transmission assets, the remuneration scheme that applies should not exactly correspond to the costs actually incurred in undertaking the resulting network investments. Instead, this scheme should set some incentives driving the TSO to carry out network expansion planning, network construction, operation, and maintenance activities efficiently (Olmos et al., 2018). On the other hand, when stakeholders undertaking network investments carry them out at their own risk, allowing these parties to retain part of the benefits created by these investments, not setting a pre-established limit to their revenues, should drive them to promote at least some of the investments that would be beneficial for the system (Olmos et al., 2018).

Notwithstanding the complexities of determining the cost of efficient investments, benefits from cross-border offshore grid projects may be difficult to assess. Hogan (2018) breaks down total net economic benefits to consumer surplus, producer surplus, and transmission congestion rents. Consumer surplus is the difference between the total load benefit and the payments made by the load; producer surplus is the difference between the revenue received by producers less the total cost of production, and transmission congestion and loss rent is the difference between the payments made by load and the revenue received by producers; this could be treated as the revenue paid to the owners of transmission rights.

The existence of difficult-to-quantify benefits does not lead inexorably to cost socialisation. If the total quantifiable benefits exceed the transmission investment cost, then allocating in proportion to the quantifiable estimates would be consistent with efficient investments; the beneficiaries would be better off with the expansion and this allocation than they would be without the expansion (Hogan, 2018). In the case that the easily quantifiable benefits are less than the investment cost, but the subjective estimate is that the total benefits are greater, the challenge would be to estimate the subjective distribution of those subjective benefits; in the extreme case, a regulator could decide that the subjective benefits are evenly distributed over all load or all generation (Hogan, 2018).

The emergence of new offshore infrastructure configurations, integrating vectors, directional, and temporal flows, requires new, innovative frameworks to enable their development and operation. This arguably lies outside the functions of the conventional TSO: there are potentially two features of these systems that make the issues that might be faced by TSOs distinctive: first, the resource base endowment as well as the costs and benefits of grid development are distributed unevenly across territories, systems, and actors. Offshore renewable sites can cross national jurisdictions, requiring economic and political agreements among governments. This raises issues around the ownership, development, and operation of offshore grid infrastructure.

Second, the existing organisation of the sector can prevent the discovery of an optimal solution to cross border cost allocation. Power system reforms of the 1990s separated the ownership of the competitive or contestable sectors (typically generation and retailing) from the ownership of the network sectors (transmission and distribution). However, structural separation has led to some loss in economies of coordination across the separated sectors. Further, regulatory schemes of network companies in many countries are primarily designed to incentivise cost efficiency, thus deterring TSOs from undertaking projects that might be considered as “risky” (Poudineh et al., 2020).

TSOs face a dilemma in this regard: on the one hand, they must innovate their operations and modernise their grids in response to the transformation brought about by decarbonisation of the energy sector; on the other hand, they must keep their costs under control in order to relieve pressure on ratepayers or deliver good financial performance for their shareholders (Biancardi et al., 2021).

In summary, there are three implications that arise from a review of the literature: first, a simple allocation of investment costs of an interconnection or hub project among its beneficiaries will not necessarily be aligned with the benefits they draw from it; second, the complex multi-vector nature development of offshore renewables (e.g., Power-to-X) further complicates the assessment and allocation of costs and benefits; and, third, this is further exacerbated by the allocation of property rights to regulated natural monopoly of TSOs, thus creating a fragmented multi ownership structure.

## 4. A model for enabling shared infrastructure investments

The main planning framework for an integrated development of energy infrastructure in the EU is the Ten-Year Network Development Plan (TYNDP). The biennial TYNDP reports identify infrastructure gaps in the existing European grid based on a modelling exercise and evaluate new cross-border transmission projects, that have been submitted by the project developers, in a Cost-Benefit Analysis (CBA). The identification of system needs is based on an extensive techno-economic optimisation that identifies interconnections that would reduce the overall cost of supply of electricity, gas, and hydrogen in Europe within the given constraints of emission reduction and renewable energy targets.

The CBA on the other hand evaluates the submitted projects also in other dimensions such as the social cost of emissions, system adequacy or security of supply. Specific benefit indicators are also determined by the ENTSOs in line with criteria set out in the TEN-E regulation, such as sustainability, market integration, security and quality of supply, as well as smart sector integration. The calculation of net impacts through CBA is described by the following formula (ACER, 2023; EC, 2021):

$$\sum_{t=f}^{c+(x-1)} \frac{B_t + F_t - C_t}{(1+r)^{(t-y)}} \tag{1}$$

Where, $f$ is the first year where costs are incurred, $c$ is the first full year of operation of the project (or project cluster), $x$ is the years considered for the assessment time horizon, $y$ is the year of the analysis (the year of the submission of the investment request), $r$ is the social discount rate used to discount benefits and costs, $B$ are all the benefits assessed by the project-specific CBA, $F$ are all the benefits assessed in the analysis of other cross-border monetary flows, and $C$ is the sum of costs. The concept of "benefits" is used to measure (in monetary terms) all advantages (or disadvantages) of a project to society or parts of society, such as TSOs. Some, but not necessarily all the economic benefits (or negative effects), can translate into cash flows. When this is not the case, they constitute externalities (ACER, 2023).

Efficiently incurred investment costs, which exclude maintenance costs, are borne by the relevant TSOs (or project promoters) of the transmission infrastructure of the countries to which the project provides a net positive impact. Similarly, compensations may be provided to countries in which the project may have an overall net negative impact. If the net negative impact is higher than the total amount of the expected efficient investment costs, cross-border cost allocation decisions may compensate the net negative impact up to the maximum amount of the expected efficient investment costs, or up to an amount at which countries become neutral to the project going ahead (ACER, 2023).

### 4.1 The shortcoming of the conventional CBA model

The original attempt to coordinate investment in transmission and generation in a liberalized electricity market was through setting cost-reflective transmission tariffs to guide generation location decisions (Newbery, 2024). The current process only serves for the planning of network infrastructure and is yet to evolve to include offshore renewable hub infrastructures, where cost and benefits of up- and downstream assets blur with those of (pipe)lines. Furthermore, while the assessment of system needs is integrated for electricity and gas, the CBA methodologies differ between gas and electricity projects and might therefore not assess hub infrastructures that can involve different energy vectors adequately. While the CBA framework is a practical tool, it is not efficient within the established structures and organisation of the sector.

From a methodological perspective, the above approach to cross border cost-benefit allocation presents a conventional CBA while the aim of the exercise to measure net social welfare gains is something that requires a comprehensive Social Cost Benefit analysis (SCBA). Determining the costs and benefits dynamically for a grid investment that will evolve in stages and over time is also a difficult task. The task is further complicated by the fact that most of the investment costs occur upfront and in early years of the project while the benefits are mainly in the long-term and thus inherently uncertain to estimate.

For cross border cost allocation the core issue is the *uneven distribution* of costs and benefits arising from the projects. Existing mechanisms do not address this sufficiently. The presence of the ACER as a mediator of last resort and the Connecting Europe Facility (CEF) can lead to strategic behaviour. An alternative assessment is that CBA is based on a "potential" net benefit being present, rather than an actual one, and that the distributional implications can be addressed outside the scope of the CBA exercise by side payments.[3]

Preceding sections show that the energy transition will require fundamental changes in the structure and operation of the energy sector, with technological, market, regulation, and policy changes that challenge the conventional governance and organisation of the sector at national as well as cross border levels. For these changes to achieve their full potential, there is a need to revisit the established arrangements for the structure, the roles, rights and duties, and distribution of property rights among the key actors in the sector (Brousseau and Glachant, 2008), which date back to early days of liberalisation of the energy sector. The evolving role of energy TSOs as key enablers is no exception, as the traditional roles and responsibilities of established actors (e.g., in this context TSOs, DNOs, and consumers) in the energy sector are being redefined. We propose a redefinition of the organisational scope of TSOs to adapt the sector to this wider transformation.

### 4.2 A proposed JV framework for offshore energy hubs

In terms of structure and organisation of the energy sector, reverting to a traditional transaction cost in a "market vs. hierarchy" boundary view of the firm (Williamson, 1975: 1981), energy grids as natural monopoly activities do not readily lend themselves to models of organised wholesale or retail energy markets. Setting the 'market' model aside, on grounds of not being feasible in a regulated natural monopoly context, the 'hierarchy' view of the firm presents three other potentially competing models of organisation of firm:

(i) The integration model,
(ii) The long-term contracts model, and
(iii) The Joint Venture (JV) model (Kogut, 1988).

While an *integration* scenario of energy TSOs in the North Sea region is conceptually feasible, it is difficult to justify this model. Most realistically, one could imagine a de-facto integration of only the offshore or hub activities. At national level, regulation would be needed to allow for different regimes for offshore or hub activities, than for regular land-based transmission. These offshore regimes could be mutually aligned for hub TSOs, thus effectively integrating offshore or hub activities. Alternatively, integration would be realised through mergers and acquisitions, based on common interests of firms around cross-border activity that is significant, but not the largest part of their business. This latter model seems highly unlikely.

[3] The Kaldor Hicks criterion. Kaldor (1939), Hicks (1939).

The *long-term contracts model* resembles the current state of the cross-border grid development and the recurrent cost allocation issue, which has led to a proposed cost-benefit analysis (CBA) based approach (ACER, 2023). We have already established the reasons why the CBA approach is not suitable to offshore renewable or “hub” infrastructure.

Within the above classification, Joint Ventures (JVs) can be viewed as an intermediate organisational form (Balakrishnan and Koza 1989). A JV is a purposeful alliance of firms that can be studied from the perspective of transaction cost economics. This placement also holds in the case of a regulated natural monopoly JV. In a transaction economics context, such alliances are characterised as “hybrid” organisations – i.e. neither ‘market’ nor ‘hierarchy’, but as having governance characteristics that places them somewhere between these two polar forms (Oxley et al., 2008). The JV binds the participating firms together through the ownership of the joint assets and their shared interest in maximising the value of these. The contractual arrangements within the JV are governed by the virtue of expressed interest in participation in the construct, while in the market perspective contracts are ultimately enforced by court order, or in the hierarchy perspective by non-legal internal agreements of the organisation (Oxley et al., 2008).

Offshore energy development benefits from collaborative development of hub infrastructure, with a likely net welfare gain to be had from the development of offshore energy resources. However, as discussed earlier, resource endowments as well as the costs and benefits of realising them are often distributed unevenly across jurisdictions. At the same time, the existing structures and organisation of the sector can prevent feasible solutions for cross border cost allocation from emerging.

In the energy sector the concept of markets vs. hierarchies has been used to describe the liberalisation of the electricity sector from centralised to market-based structures (Joskow, 2021). In this study we use the paradigm as analogy to describe a setting in which several TSOs independently pursue their own interests as the ‘market’ through bargaining and negotiation, while ‘hierarchy’ refers to a single entity that internalises and aligns the sometimes differing interests of the actors.

We propose a JV solution organised through regulated natural monopolies to facilitate the development of offshore hub infrastructure as sketched in figure 1. The JV model separates the decision to invest in the energy hub, from the, currently difficult, discussion of cost allocation and benefit determination among the actors. The concerned TSOs, at the core, as well as users connected directly at the hub can then enter contracts with the JV for the use of the hub services. As mentioned earlier, this approach is also underscored by the logic of collective action by shared interest among the most concerned countries. The proposed JV solution, in effect, “de-links” the investment cost of grid development from its cost of use and benefits for the individual TSO.

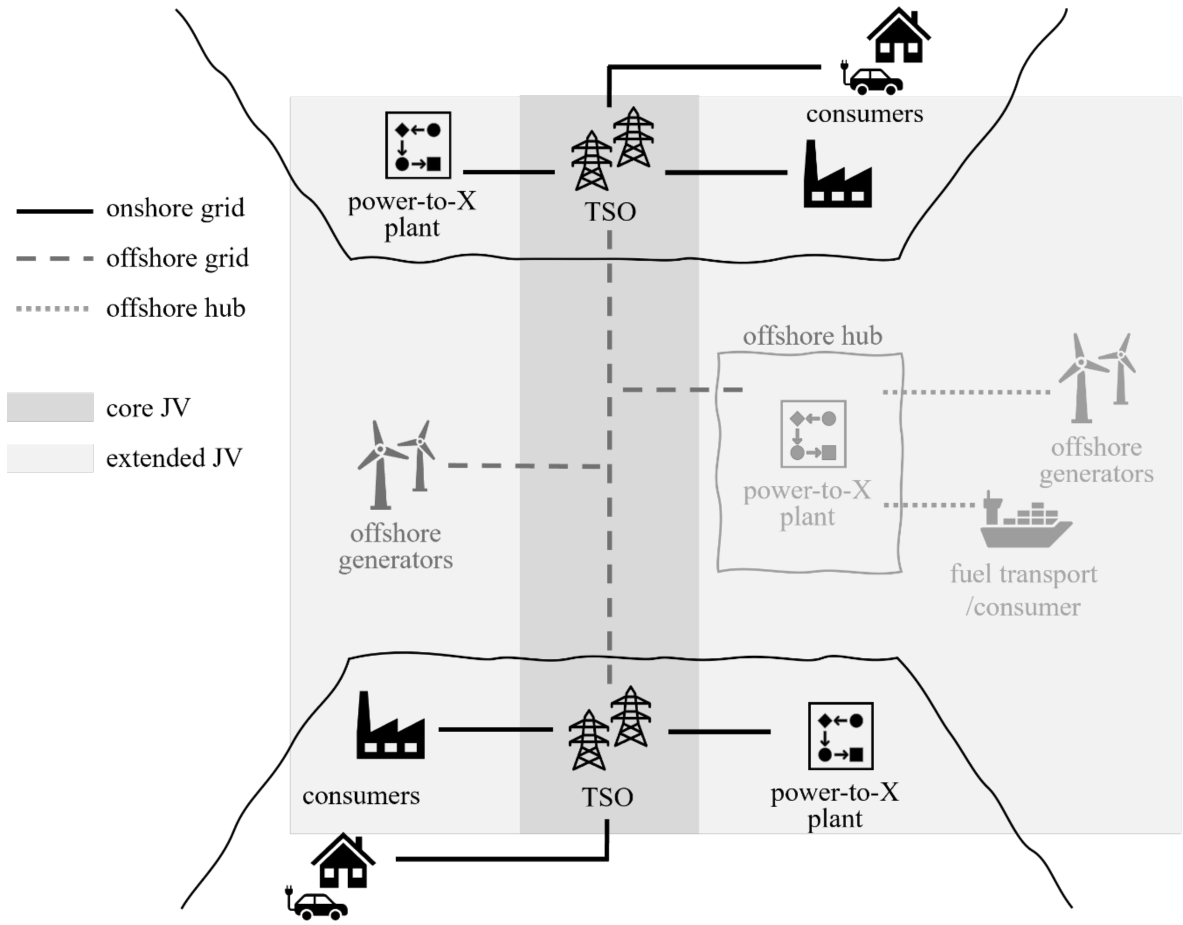


Figure 1: Sketch of an offshore grid and hub JV

The JV model of hub organisation can form the basis of a stable collaborative framework for the development of the energy hub, in the form of a new and regulated natural monopoly entity that will combine "regulation by contract" among the partners and supplementary oversight by "regulation by agency" (Stern, 2012). The main role of the JV entity will be to serve the energy system that will come to depend on it efficiently and at the lowest cost. Considering the specialised nature of the assets of an (offshore) energy hub, the degree of asset specificity of such a JV is high.

The proposed JV would be a new regulated infrastructure entity that operates the hub on commercial basis. Also, given the central position of an offshore energy hub in the sector, a JV is well placed to utilise the value of these assets and its core competence for the benefit of the wider energy sector and constituent firms. The JV could be owned by the relevant TSOs at the core, and in an extended framework also by hub or network users or even commercial investors. Further, ownership shares do not need to correspond to their expected costs or benefits associated with their use of the hub services, as these are de-linked in the JV. Individual TSOs could each negotiate the terms and costs of access to the grid with the JV. Once investment costs and benefits allocation are decoupled, the issue becomes a conventional grid access and development matter, for which there are existing, although imperfect, models.

There is precedent and experience for JV-based arrangements in for instance, the North Sea oil and gas sector.[4] [5] During the productive years of North Sea oil and gas fields, companies could bid to participate in JVs in which a state-owned company would retain a share of ownership; one of the JV partners would also act as operator managing the field on behalf of the members on a non-for-profit basis. Once production commenced, each JV partner would receive a share of production commensurate with its ownership share, subject to the terms of the JV agreement (which may lessen this share by the amount of costs incurred by the operator). While governments (who were the owners of the offshore resource) earned revenues through taxes, royalties and fees – oil companies (in the JV) bore the risks of the investment (van Shaik, 2012). More recently, 'Super JVs' are being used to incentivise technological innovation as North Sea field production declines and the depleted fields move into the decommissioning phase, as part of countries' net zero plans.[6]

The potential use of joint or shared entities has also been stipulated in the EU regulation. Regulation (EU) 2022/869 defines that a 'project promoter' can "in the case of more than one […] TSO, DSO, other operator or investor, or any group thereof, the entity with legal personality under the applicable national law which has been designated by contractual arrangement between them and which has the capacity to undertake legal obligations and assume financial liability on behalf of the parties to the contractual arrangement". ACER's 2020 CBCA report lists at least one cross-border cost allocation decision for electricity (maybe more for gas) where the applicant appears to be a Joint Venture: namely the Eurasia project between Greece, Cyprus and Israel.

### 4.3 Advantages of a JV model

A JV framework is superior to a bilateral negotiations model over cost-benefit allocation in several ways. First, it reduces the complexity of negotiations by aligning the incentives of different actors in the JV. When more than two actors are involved, multilateral negotiations become increasingly more complex. Second, infrastructure development in the North Sea and Baltic Sea regions will be gradual and dynamic. Relying on a continuous negations model could complicate their future developments. A JV with the remit for long-term infrastructure planning will be better able to manage an evolving grid. Third, the JV model could facilitate a negotiated outcome among partners, which is preferable to a more contract-based framework among several stakeholders.[7] Finally, a JV model can reduce the need for financial support and subsidies (e.g., from the CEF funding designed to promote implementation of Projects of Common Interest across the EU).

[4] The North Sea petroleum JVs were economic rent generating activities. A hub JV will be a regulated utility.
[5] Concerned state(s) may hold specific economic interests in the JV as a critical infrastructure as in the case of the Norwegian North Sea petroleum fields in the form of State Direct Economic Interests (SDØI) managed by the state-owned oil company Statoil.
[6] https://pwc.blogs.com/files/a-sea-change---the-super-joint-venture.pdf
[7] The JV model is not a strictly Coasean (re)allocation of property rights, but is in a similar vein. It reduces negotiation cost and opens for a "collaborative", instead of a "bargaining" based framework, that aims to benefit from "network externalities" of a shared infrastructure.

The proposed model based on a regulated JV made up of several national natural monopolies concerned meets the *necessary* and *sufficient* conditions underpinning the theoretical justification for regulation of natural monopolies. Therefore, by the same logic, the natural monopoly feature of declining average costs and economies of scale also holds for the proposed JV of natural monopolies comprising several natural monopolies.[8] This feature together with the interdependence of the interests reduces geopolitical uncertainty and commercial risks arising from the member countries.

A contract-based arrangement, such as a bilateral or multilateral agreement, would be inferior to a cooperative JV model under regulatory oversight. Transaction costs in a JV model would be lower and the model is more suitable for long-term development of the hub that maximises network externalities. A CBA approach to allocate the investment costs and benefits also has shortcomings. For instance, if there is a net social welfare gain to be had, the distributional implications of a CBA can potentially be resolved outside of its framework. However, while this may offer possibilities for a broad negotiation framework, the inherent difficulty of finding an economic solution remains.

### 4.4 Barriers and residual challenges

A JV framework is a conceptually superior solution to the existing options that enables offshore infrastructure-related investment to proceed, by separating the decision to invest from the decision around cost and benefit allocation. It also provides a resolution to the use of veto power by third parties that might halt such an investment, assuming there are no net negative benefits that would need to be compensated. In this sense, it is a starting point or a guiding post towards catalysing investments, which sits outside of the conventional CBA approach.

However, implementation of the proposed model is unlikely to be without challenges. For instance, it requires a willingness to participate on behalf of the relevant parties – if these are TSOs, their remit or scope may have to be amended as appropriate. Further, it does not fully resolve the issue of bargaining power of concerned jurisdictions – which is associated with political economy issues that lie outside the scope of this paper. However, the early political declarations given signalling the willingness to cooperate on development of the renewable resources and infrastructure reinforces the notion of logic of collective action in the North Sea region.

## 5. Conclusion

The current structure of the energy sector, based on the liberalised market paradigm of the 1990s, is not yet fully conducive to addressing new challenges posed by a rapidly decarbonising sector facing high levels of electrification: first, a simple allocation of investment costs of a hub among its beneficiaries (e.g., countries) is not necessarily aligned with the benefits they draw from it; second, the complex technical nature of offshore renewable hubs further complicates the assessment and allocation of costs and benefits;

[8] See Joskow (2007) for a detailed treatment of natural monopoly regulation.

and, third, this complexity is further exacerbated by the current allocation of property rights and definition of roles to the key actors.

At the same time, TSOs face a dilemma: on the one hand, they need to innovate and modernise their grids in response to the transformation; on the other, they need to keep costs under control to relieve pressure on ratepayers and maintain financial performance for shareholders. We propose a solution to resolve this dilemma based on the logic of collective action – namely that a subset of EU member states have the shared incentive to cooperate on joint development of the resources and hubs.

We then outline a Joint Venture framework solution that decouples the decision to invest from the decision around the allocation of costs and benefits across actors, enabling projects that are essential for the energy transition to proceed. We present the theoretical advantages of a JV framework. Finally, we outline some residual challenges that will need to be addressed separately, as the transition progresses.

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