A Mechanism for Allocating Benefits and Costs from Transmission Interconnections under Cooperation: A Case Study of the North Sea Offshore Grid

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ABSTRACT

We propose a generic mechanism for allocating the benefits and costs that result from the development of international transmission interconnections under a cooperative agreement. The mechanism is based on a planning model that considers generation investments as a response to transmission developments, and the Shapley Value from cooperative game theory. This method provides a unique allocation of benefits and costs considering each country's average incremental contribution to the cooperative agreement. The allocation satisfies an axiomatic definition of fairness. We demonstrate our results for three planned transmission interconnections in the North Sea and show that the proposed mechanism can be used as a basis for defining a set of Power Purchase Agreements among countries. This achieves the desired final distribution of economic benefits and costs from transmission interconnections as countries trade power over time. We also show that, in this case, the proposed allocation is stable.

Keywords: Cooperative game theory, Cost-benefit allocation, Transmission expansion planning

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1. INTRODUCTION

Many countries in the European Union (EU) plan to incorporate large shares of electricity supply from renewable energy technologies—particularly solar and wind power—in the coming decades (ECF, 2011). Unlike conventional generation technologies, the variability and unpredictability of renewable resources result in higher needs for flexibility in order to maintain the reliability of a power system (Denholm and Hand, 2011). One source of flexibility is the possibility of balancing distinct generation resources and demand across large geographical areas through high-voltage transmission lines (Munoz et al., 2012; Konstantelos and Strbac, 2015). Distant wind farms, for instance, can present synergistic effects by geographic diversification (Hasche, 2010), which can reduce the need for other sources of flexibility such as storage and fast-ramping generation units.

Transmission interconnections are one way to capture the benefits from the spatial diversification of resources. They can also result in economic and environmental benefits from avoided fuel costs, postponement of local generation investments and transmission reinforcements, and reductions in aggregate carbon emissions due to power exchange (UN, 2006). For these reasons, the EU Commission has identified the North Sea Offshore Grid (NSOG) as one of the strategic trans-European energy infrastructure priorities in the EU Regulation No 347/2013 (EUL, 2013). In a recent study,

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Strbac et al. (2014) estimate that the aggregate economic benefits from the NSOG are between €8bn and €40bn depending on the level of coordination that participant countries will achieve.

In practice, achieving a cost-effective portfolio of transmission developments for a NSOG from a system-wide perspective can be quite challenging since there is no centralized authority with the legal power to force countries to accept the proposed plan. The latest development plan by the European Network of Transmission System Operators for Electricity (ENTSO-E), an organization that promotes cooperation across Europe's Transmission System Operators (TSOs), states that nearly €150bn worth of investments will be needed for pan-European infrastructure expansions in order to meet projections of demand and environmental targets at minimum cost by year 2030 (ENTSO-E, 2016). However, it is not clear how many of the proposed projects are actually supported by individual countries in the region.

A unique feature of international transmission interconnections is that they can be unilaterally vetoed by a country at one end of the proposed project if it considers 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[1] and investment cost of the transmission line). We refer to these as *host countries*. Moreover, *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. Ignoring the impacts on third-party countries could result in political tension among members of the interconnected system or failure to realize the full benefits of a highly interconnected grid. For instance, 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. 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. One possible threat is to arbitrarily reduce the degree of coordination in the hourly dispatch of local generating resources with the rest of the system, a measure that could increase costs in some neighboring regions. A third-party country could also refuse to provide a required amount of balancing services in a synchronized area and cause frequency deviations that could put the system stability of an entire interconnected region at risk.[2] Consequently, achieving all the economic benefits that would, ideally, result from international transmission interconnections might require more than just bilateral agreements between hosting countries. Building a broad consensus among all countries in a region to support transmission interconnections is, in fact, in the spirit of Regulation (EU) No 347/2013 (EUL, 2013).[3]

Failure to achieve an agreement to develop a cost-effective portfolio of transmission investments in the region can also have an impact in the location, size, and type of new investments in generating capacity (Sauma and Oren, 2006; Munoz et al., 2013, 2014). For instance, many of the proposed transmission projects in the NSOG are actually needed if countries have goals of harnessing the vast amount of onshore and offshore wind resources available in the North Sea (Konstantelos et al., 2017a; Gorenstein Dedecca et al., 2018). If these are not developed, it is likely that demand projections and environmental goals will be met with less efficient resources at a much higher cost

[1] Congestion rents are defined as the price difference times the power flow over a transmission asset.

[2] During early 2018, the entire Continental European Power System experienced a continuous frequency deviation as a consequence of a political conflict between Servia and Kosovo. The frequency deviation occurred because Servia refused to balance Kosovo's system during a shortage of power supply in the latter (ENTSO-E, 2018)

[3] Annex V in page 72 of EUL (2013) describes a series of principles for methodologies for harmonized energy system-wide cost-benefit analysis for projects of common interests in the EU. According to principle (10), *"(t)he (proposed) methodology shall define the analysis to be carried out, based on the relevant input data set, by determining the impacts with and without the project. The area for the analysis of an individual project shall cover all Member States and third-party countries, on whose territory the project shall be built, all directly neighboring Member States and all other Member States significantly impacted by the project." Furthermore, according to principle (11) "(t)he analysis shall identify the Member States on which the project has net positive impacts (beneficiaries) and those Member States on which the project has a net negative impact (cost bearers)" (EUL, 2013).*

(e.g., distributed rooftop solar PV in areas with low radiation instead of large-scale offshore wind farms in windy regions). Large transmission investments can also change electricity prices in a network and shift investments of any type of generation technology, including conventional power plants, from one country to another (Hogan, 2018). Finding a mechanism to support the development of cost-effective portfolios of transmission investments from a system-wide perspective is, therefore, just as important as identifying them in the first place under a central-planning paradigm as demonstrated by Grigoryeva et al. (2018) and Olmos et al. (2018) for the North-Western European and Spanish power systems, respectively.

In this article we present a mechanism for allocating the net economic benefits that result from international transmission interconnections among a group of countries that are willing to reach a cooperative agreement to support a cost-effective portfolio of transmission investments. Our approach is based on a planning model that considers generator's response to transmission investments in a competitive setting and the Shapley Value (SV) from cooperative game theory. One of the great advantages of this mechanism is that it provides a *fair* and unique allocation of benefits for all countries under the so called *grand coalition* based on the average incremental contribution from each country towards the cooperative agreement. This information can then be used to determine a set of side payments among countries that will be necessary to achieve the final allocation determined using the SV. Conveniently, this allocation satisfies an axiomatic definition of fairness.

We illustrate the proposed allocation method on a network that simulates power production and trade among six countries in the North Sea region in year 2030. We consider all the possible realizations (i.e., built or not built) of three offshore transmission projects that are planned in this region: the North Sea Link between Norway and Great Britain, the NordLink between Norway and Germany, and the Viking cable between Denmark and Great Britain (ENTSO-E, 2016). We apply the proposed mechanism to this case study and compare the difference between the ideal final allocation of benefits under the SV and two conventional allocation rules that allocate transmission costs and congestion rents among countries: 50/50 split and a proportional split with respect to estimated benefits from transmission upgrades. Assuming that interconnections will be initially funded through one of these conventional allocation rules, we determine the side payments needed to achieve the SV and define a set of Power Purchase Agreements (PPAs) that will achieve the desired distribution of benefits as countries trade power over time. We also verify that, in this case, the SV is in the core because the game is convex. This means that the SV allocation is not only fair but also stable since countries have no incentives to deviate from the grand cooperative agreement by forming smaller subcoalitions. Although stability is not a general result, the proposed mechanism can be helpful in supporting cost-efficient transmission interconnection projects.

We structure the rest of the paper as follows. In Section 2 we overview existing literature on transmission planning with a focus on centralized and cooperative mechanisms. In Section 3 we discuss the reasons for which it is unlikely that decentralized mechanisms will result in agreements to support a socially-optimal set of transmission interconnections. In Section 4 we use two simple examples to show how expanding the capacity of a congested transmission line could lead to asymmetric, or even negative, net benefits for some countries in an interconnected system. In Section 5 we describe the proposed methodology, including a high-level description of the planning model and the steps to compute the SV. In Section 6 we describe the case study and present our results. Finally, in Section 7 we conclude.

2. TRANSMISSION PLANNING AND COST ALLOCATION MECHANISMS IN CENTRALIZED AND COOPERATIVE SETTINGS

Transmission planning is an active area of study, particularly in the field of operations research. This is because finding a socially-optimal plan (e.g., the one that minimizes total system costs) from a set of candidate portfolios can be computationally challenging, even if all transmission investment decisions are made by a central authority (e.g., a national energy commission or a regulated transmission organization) (Latorre et al., 2003; Hemmati et al., 2013). Large transmission networks can have millions of possible investment combinations and finding the optimal one might sometimes require the use of sophisticated optimization algorithms in combination with high-performance computers (Munoz and Watson, 2015; Munoz et al., 2016). Also, in deregulated markets transmission investments can alter electricity prices and, consequently, incentives for investments in new generating capacity (Spyrou et al., 2017). Depending on the market structure, consideration of generator's response to transmission investments might require the use of equilibrium models that involve the implementation of non-trivial algorithms to find an optimal solution (Sauma and Oren, 2006; Pozo et al., 2013). Uncertainty of input parameters such as demand, fuel costs, and carbon prices can also complicate decision making (Munoz et al., 2014, 2015), particularly if planners are risk averse (Munoz et al., 2017).

Additionally, the siting process of new transmission lines can be difficult if voluntary negotiations with landowners to obtain easements on private property fail, or if local communities or interest groups do not approve the development of new infrastructure in a determined area (Ciupuliga and Cuppen, 2013; Bertsch et al., 2016). However, these conflicts do not always result in cancellation of transmission projects. In many jurisdictions, regional transmission organizations are granted the power of eminent domain to develop infrastructure that is deemed necessary when voluntary negotiations fail (Meidinger, 1980; Rossi, 2009). Consequently, broad approval of transmission projects is desired, but not strictly necessary, in centralized planning settings.

Planning international transmission interconnections involves dealing with many of the difficulties mentioned above, but also requires consideration of additional features. Scale, for instance, is important because assessing the economic benefits of a proposed project between two countries requires concurrent simulation of operations in both systems in order to capture correlations of demand, wind, hydro, and solar profiles (if available). Scale becomes more relevant when evaluating the economic benefits that result from a set of multinational projects in an interconnected system with many independent countries or regions (Perez et al., 2016). However, the computational complexity that involves finding the so-called optimal plan in a large interconnected system (e.g., the one that minimizes expected system costs for the entire region, assuming full coordination among countries) is only a first step in a study of transmission interconnections. The next step involves finding a mechanism for allocating the economic benefits and costs that result from the proposed projects in a fair and efficient manner, such that all hosting countries support their development. Moreover, under certain circumstances, host countries might prefer to build a broader consensus and even consider the effects of new projects on third-party countries. As we mentioned in the previous section, third-party countries can experience positive or negative economic effects as a result of new grid investments elsewhere in the system (Bushnell and Stoft, 1996, 1997).

One mechanism that is often used to support transmission interconnections is the Equal Share Principle (ESP) (Jansen et al., 2015). Under this paradigm, each country hosting a new (bilateral) transmission project is responsible for financing 50% of the capital costs of the transmission project and gets a 50% share the congestion rents that result from the power exchanges between countries at local prices. There are also variants of this mechanism based on the principle that beneficiaries pay (Hogan, 2018). This paradigm is applied in the U.S., where FERC has a rule which establishes that "*(t)he cost of transmission facilities must be allocated to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits*" (FERC, 2012).

In 2013, the Agency for the Cooperation of Energy Regulators (ACER) proposed the use of the Positive Net Benefit Differential (PNBD) principle as a mechanism to support transmission interconnections in the EU (ACER, 2013). The PNBD allocates transmission costs in proportion to estimated (positive) benefits as a result of new transmission projects. Konstantelos et al. (2017b), for example, compares two different versions of the mechanism. In one version, third-party countries that are worse off as a consequence of the new infrastructure are compensated through side payments from hosting countries that leaves them with zero net benefits compared to a reference case (e.g., no interconnections). These compensations are also prorated in proportion to estimated benefits. In the other version, third-party countries are not considered for compensation payments, which reduces the complexity of the mechanism. However, this variant might result in free-riding issues that could lead to political conflicts among countries (Jansen et al., 2015). While the PNBD can indeed help in building broad consensus to implement transmission interconnections because, by design, it results in nonnegative net benefits for all individual countries in a region, there is no economic principle that underlines the final allocation of benefits and costs under this mechanism.

We can think of three weaknesses of the methods mentioned above. First, they neglect the incremental economic value that results from a country's support for one or a set of transmission projects (e.g., changes in net benefits for all countries if one nation decides not to support a project). For instance, countries with abundant flexible generation, such as hydro in Norway, may be responsible for a large fraction of the cost savings that result from an integrated NSOG network. Based on this information, they would probably expect to receive a large fraction of economic benefits in return for providing such flexible resources. Second, these methods also disregard how the deployment sequence of transmission projects can affect estimates of the economic value of the proposed portfolio of grid investments (e.g., incremental value of a project for the system if it is considered first or last in a sequence of installations) (Banez-Chicharro et al., 2017). Finally, they ignore incentives for countries to form smaller subcoalitions and achieve higher payoffs than under a grand cooperative agreement. Any of these features could weaken incentives for countries to join the grand coalition and lead to failure to implement a socially-optimal set of international transmission interconnections (Nylund, 2009).

An alternative allocation mechanism is the Shapley Value from cooperative game theory (Shapley, 1953). By construction, the SV takes into account the average incremental contribution of each country towards the grand coalition, considering all possible development sequences. The result is a fair allocation of net benefits, ignoring strategic incentives for parties to deviate from the grand coalition. However, under certain conditions the resulting allocation can also be stable—meaning that involved parties lack incentives to deviate from the grand coalition. Different versions of the SV have been proposed as frameworks for achieving fair allocations of net benefits among consumers and producers in different locations in a transmission network (Contreras and Wu, 1999, 2000; Zolezzi and Rudnick, 2002; Erli et al., 2005). In a report by the North Seas Countries' Offshore Grid Initiative (NSCOGI, 2014) the authors consider the SV as one possible mechanism to allocate transmission costs among cooperating countries in the NSOG, but that study ignores the possibility of using side payments to achieve a fair distribution of net benefits. To our best knowledge, ours is the first study that proposes the use of the SV as a mechanism to distribute both benefits and costs in the context of international transmission interconnections, such as the NSOG.

3. WHY DECENTRALIZED APPROACHES FOR TRANSMISSION PLANNING MIGHT FAIL TO ATTAIN A SOCIAL OPTIMUM

While international transmission interconnections do require some form of agreement between host countries with direct veto power, centrally-coordinated benefit (or cost) allocation mechanisms (e.g., equal share, PNBD, SV) are not the only option to support the development of new grid projects in an interconnected system. One decentralized, or free-market, alternative is to let countries freely negotiate the final allocation of benefits and costs from a socially-optimal plan of transmission interconnections identified by some international organization (e.g., ENTSO-E or ACER). This could be achieved through an iterative process of multilateral bargaining (Krishna and Serrano, 1996), where each country negotiates the minimum share of net benefits that it would be willing to receive based on its bargaining power. For example, a host country with the power to veto a transmission project that results in large economic net benefits for all neighbors in the region has strong bargaining power. It is likely that this country will only agree to host the new transmission line if it gets a large share of those net benefits. Furthermore, a third-party country that will experience positive net benefits as a result of a new project might voluntarily join the negotiations and offer to bear a share of the development costs. Host countries might also consider it beneficial to provide some form of economic compensation to third parties that will be worse off if the cost of political tensions outweigh the costs of providing such compensations.

In theory, if there are well-defined property rights and no transaction costs, a decentralized bargaining mechanism could achieve an efficient outcome (Anderlini and Felli, 2006), in line with the *Coase Theorem*. However, there are some features of the bargaining mechanism that could result in a failure to implement a socially-optimal set of transmission interconnections. First, the Nash bargaining solution does not always lead to a socially-optimal outcome (i.e., the one that is optimal for the grand coalition) if there are more than two agents involved in the negotiation. This is because the optimal solution of the Nash bargaining problem ignores the possibility of cooperation among subsets of players (Narahari, 2014). Consequently, if all subcoalitions can negotiate effectively, agents will have incentives to deviate from the bargaining problem that involves all parties if some subcoalition offers more net benefits than what they would get under the grand coalition (Myerson, 1997). Second, bargaining can be costly due to transaction costs or discounting factors if parties are impatient. In such settings, trade can yield an inefficient allocation of net benefits and, in some cases, it might not even occur (Perry, 1986; Cramton, 1991; Anderlini and Felli, 2006). Third, in a decentralized planning setting, countries could act strategically by over or underinvesting in local infrastructure projects that would shift rents to their constituents (Huppmann and Egerer, 2015), which would then deviate investments from the socially-optimal ones. Finally, Joskow and Tirole (2005) provide strong arguments against the thesis that multilateral bargaining will effectively lead to an agreement among all winning and losing parties as a result of large and lumpy transmission projects (i.e., the Coase Theorem).

Merchant transmission investments can also be used as a decentralized solution to international transmission interconnections. These rely on competition and market-based pricing to incentivize new transmission capacity. It has been demonstrated that under a certain set of conditions that include nodal pricing, perfect competition, well-defined property rights, and no increasing returns to scale, all profitable transmission investments are efficient investments (Hogan, 1992; Bushnell and Stoft, 1996, 1997). Unfortunately, the converse is not true and not all socially-optimal investments are profitable. Doorman and Frøystad (2013), for instance, show that many transmission interconnection alternatives between Great Britain and Norway do increase social welfare (net of transmission investment costs), however, they are not profitable from a merchant perspective. Egerer et al. (2013) reach the same conclusion, but considering more investment alternatives in the region. Gerbaulet and Weber (2018) repeat the analysis for the region using a more sophisticated approach, where there is a merchant investor that makes decisions anticipating an optimal response of the regulator in building other transmission lines (i.e., as a Stackelberg leader). While in this case merchant investments can capture nearly 70% of the welfare gains that result from transmission interconnections, almost all of those gains are collected by the merchant transmission firm and some countries end up worse off as a result of these developments. However, all of these studies rely on a series of strong assumptions. Joskow and Tirole (2005) show that merchant transmission projects can yield much worse results than expected if, for instance, electricity prices are distorted due to market power of generation firms or if there is gaming between independent merchant transmission investors. For these reasons, few merchant transmission projects have been approved by the EU Commission and seeking approval for new ones has become much more difficult over time (Cuomo and Glachant, 2012).

4. COMPARATIVE STATICS OF TWO- AND THREE-NODE SYSTEMS

In this section we present some counterintuitive effects of transmission investments on welfare at aggregate and regional (i.e., nodal) levels using two stylized networks. We show that although more trading of electricity between regions, as a result of new transmission capacity in congested lines, always result in nonnegative changes of welfare and net welfare[4] in aggregate terms, changes in benefits or costs as a consequence of more trading can be unevenly distributed among regions. In fact, transmission capacity that is optimal from a system-wide perspective (i.e., that maximizes aggregate welfare for all regions) could leave some regions worse off, which can create difficulties for the development of new projects that are not centrally coordinated since the involved parties might not have incentives to support them.

We assume that the demand for electricity at each node is inelastic (i.e., the demand does not respond to changes in price), with a high price ceiling equal to the value of lost load (VOLL).[5] Moreover, we assume linear long-run supply functions and perfect competition. The analysis is static, meaning that we look at one representative market state, with and without additional transmission capacity. Finally, we choose to isolate the impact of congestion rents (CRs) on welfare metrics in both examples because CRs and transmission investment cost cancel each other out at socially-optimal investment levels under ideal conditions (e.g., no increasing returns to scale, no market power, efficient nodal prices, free entry, etc.) (Hogan, 2018; Joskow and Tirole, 2005).

4.1 Asymmetric benefits in a two-node system

Consider first a system composed of nodes (countries) 1 and 2, with demands d_1 and d_2, respectively, such that $d_1 < d_2$, and a transmission line with capacity K. We denote generation levels at each node q_1 and q_2 and assume linear supply functions, $c_1(q_1) = c_0 + a_1 q_1$ and $c_2(q_2) = c_0 + a_2 q_2$, which represent the long-run marginal cost of generation at each node. Node 2 has a generation mix with a higher marginal cost than generation at Node 1, thus, we assume $a_2 > a_1$. Since $VOLL >> 1$, demand is never curtailed and total demand equate total generation; $d_1 + d_2 = q_1 + q_2$. For simplicity, we only consider transmission capacities K that result in a congested line between nodes 1 and 2. This is true as long as the capacity K induce higher generation costs than what could be achieved by the cheapest generator alone, i.e. the marginal cost of supplying both node 1 and 2 with generator capacity at node 1; $c_1(d_1 + d_2) < c_1(d_1 + K) + c_2(d_2 - K)$, where $0 \leq K \leq d_2$. Consequently, the equilibrium quantities and prices are $q_1 = d_1 + K$ and $p_1 = c_1(d_1 + K)$ for the exporting node, and $q_2 = d_2 - K$ and $p_2 = c_2(d_2 - K)$ for the importing node. Table 1 summarizes dispatch levels, prices, and welfare metrics per node for this system.

Figure 1 shows changes in nodal welfare (W_i), consumer surplus (CS_i), producer surplus (PS_i), and congestion rent (CR) when increasing the capacity of the line from $K = 0$ to $K > 0$, disregarding any transmission cost. The consumer surplus is the area below the VOLL and above the price, p_i, i.e. the surplus that the consumers see in terms of their maximum willingness to pay for electricity. Contrary, the producers see a surplus between their marginal cost of production and the price, p_i. The CR is determined by the price difference and trade/capacity between two, or more, connected nodes. CR is therefore zero when the trade-capacity is zero.

The following assertions are true for this system:

1. *Consumer surplus:* An increase in K benefits consumers at the importing node ($\frac{dCS_2}{dK} = a_2 d_2 > 0$) since the price declines ($\frac{dp_2}{dK} = -a_2 < 0$). In contrast, consumers at the exporting node are worse off as a result of an increase in the transmission capacity between nodes 1 and 2 ($\frac{dCS_1}{dK} = -a_1 d_1 < 0$) since exports drive local prices up ($\frac{dp_1}{dK} = a_1 > 0$).

[4] In this article we define net welfare as welfare (i.e., the sum of consumer and producer surplus) plus congestion rents.

[5] The value of lost load reflects the economic cost of curtailing one MWh of electricity demand. Here we use it as an estimate of the maximum willingness to pay for an additional unit of energy.

Table 1: Equilibrium results for nodes 1 and 2. Note that transmission investment costs are disregarded from welfare metrics. For net welfare we assume that nodes 1 and 2 receive a fraction of congestion rents equal to α_1 and α_2, respectively, such that $\alpha_1 + \alpha_2 = 1$ (e.g. $\alpha_1 = \alpha_2 = 0.5$).

Metric	Node 1	Node 2	System
Dispatch levels	$q_1 = d_1 + K$	$q_2 = d_2 - K$	$q_1 + q_2 = d_1 + d_2$
Price	$p_1 = c_1 = c_0 + a_1 q_1$	$p_2 = c_2 = c_0 + a_2 q_2$	–
Producer Surplus (PS)	$\frac{1}{2}(p_1 - c_0)q_1$	$\frac{1}{2}(p_2 - c_0)q_2$	$PS_1 + PS_2$
Consumer Surplus (CS)	$(VOLL - p_1)d_1$	$(VOLL - p_2)d_2$	$CS_1 + CS_2$
Congestion Rent (CR)	$\alpha_1(p_2 - p_1)K$	$\alpha_2(p_2 - p_1)K$	$CR_1 + CR_2$
Welfare (W)	$PS_1 + CS_1$	$PS_2 + CS_2$	$PS + CS$
Net Welfare (W+CR)	$PS_1 + CS_1 + \alpha_1 CR_1$	$PS_2 + CS_2 + \alpha_2 CR_2$	$PS + CS + CR$

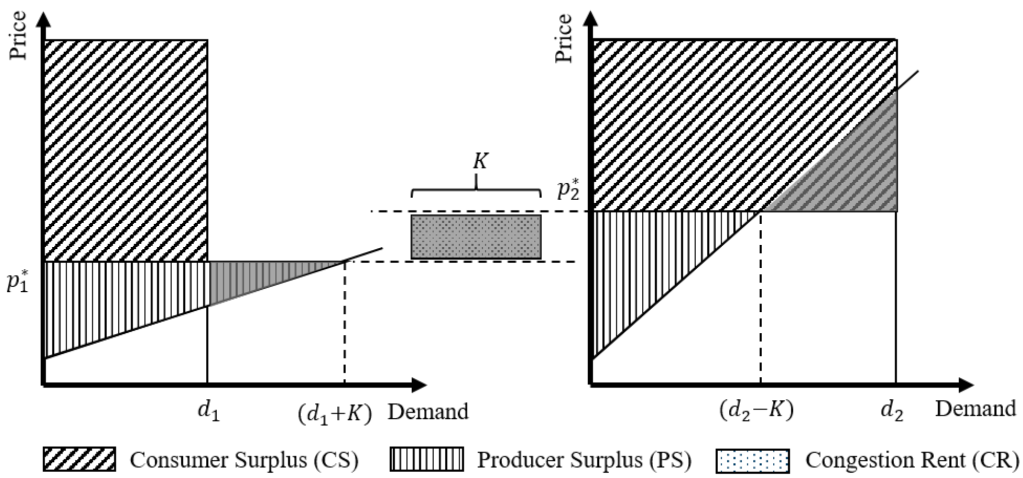

Figure 1: Net welfare effects (dark shaded areas) of new transmission capacity between a low price area (Node 1) and a high price area (Node 2).

2. *Producer surplus:* Producers at Node 1 benefit from an increase in K ($\frac{dPS_1}{dK} = a_1(d_1 + K) > 0$) as the nodal price increase (see 1.). Some production at Node 2 falls out of the market when the price decreases due to cheaper import from Node 1, which reduces producer surplus ($\frac{dPS_2}{dK} = a_2(K - d_2) < 0$).

3. *Congestion rent:* $CR = (p_2 - p_1)K$ is a concave and quadratic function on K. The level K^M maximizes CR and is equal to the optimal investment level for a single merchant investor (disregarding investment costs). The level $K^* = 2K^M$ solves $CR(K) = 0$ and is equal to the socially optimal investment level, which could be achieved under full cooperation between nodes. Thus, $\frac{dCR}{dK} > 0$ for $0 < K < K^M$ and $\frac{dCR}{dK} < 0$ for $K^M < K < K^*$.

4. *Welfare:* If we disregard CR, welfare at Node 1 increases ($\frac{dW_1}{dK} = a_1 K > 0$) when the transmission capacity K increases. Welfare does also increase at Node 2 ($\frac{dW_2}{dK} = a_2 K > 0$) but at a higher rate than in Node 1 ($\frac{dW_2}{dK} > \frac{dW_1}{dK}$) since $a_2 > a_1$. Say CR is split between nodes 1 and 2 in proportions $\alpha_1 \geq 0$ and $\alpha_2 \geq 0$, respectively, such that $\alpha_1 + \alpha_2 = 1$. For $0 < K < K^M$, a marginal increase in transmission capacity always increases net welfare for both nodes, i.e. $\frac{dW_i}{dK} + \alpha_i \frac{dCR}{dK} > 0$ for $i \in \{1, 2\}$.[6] In contrast, for $K^M < K < K^*$ it is possible that a marginal increase in transmission capacity could reduce net welfare in one node for some allocation rule

[6]This is because for $0 < K < K^M$, $\frac{dCR}{dK} > 0$.

(i.e., α_1 and α_2) of CR. Yet, since $\frac{dW_1}{dK} + \frac{dW_2}{dK} + \frac{dCR}{dK} > 0$,[7] it is always possible to split the benefits of adding a marginal amount of transmission capacity to both nodes (e.g., through some form of side payments) such that the marginal change in net welfare is strictly positive at both locations.

When ignoring the allocation of investment costs and CRs in a perfectly competitive market, we see from Figure 1 and the analytical assertions that the aggregated welfare and net welfare always increases when adding capacity to a congested line. However, nodal benefits are unlikely to be evenly distributed since $\frac{dW_2}{dK} > \frac{dW_1}{dK}$, $PS_1 \leq PS_2$, and $CS_1 \geq CS_2$. Hence, some form of compensation could be required since agents at one node could unilaterally block the development of a transmission project. For instance, if we consider investment costs, one could compensate for unevenly distributed benefits by adjusting the allocation of capital cost of new transmission capacity in proportion to the benefits that result from its development (Hogan, 2018). However, under ideal conditions, this cost is equal to CRs (i.e., the line is expanded until the marginal cost of expansion is equal its marginal benefit to the system). Additionally, as we mentioned it in Section 2, such cost-allocation schemes do not take into account the incremental value of each country's support towards a socially-optimal transmission project (e.g., the power to veto the construction of a transmission interconnection). Of course, planning in the real world is much more difficult because, contrary to what we assume in these examples, transmission investments present economies of scale and capacity cannot be expanded in small increments (Joskow and Tirole, 2005; Munoz et al., 2013).

4.2 Asymmetric and negative benefits in a three-node system

We now add a medium price node to the previous example, as shown in Figure 2. The parameter K_{23} denotes the transmission capacity between nodes 2 and 3. Let's assume that the given prices reflect the connected system under operation and that there is a bilateral, voluntary, agreement to build a new transmission line between Node 1 (low price) and Node 2 (high price). Node 3 (medium price), with marginal cost $c_3(q_3) = c_0 + a_3 q_3$ and energy balance $q_3 = d_3 + K_{23}$, is still connected to Node 2 after the new transmission line is built. With more transmission capacity between Node 1 and Node 2 the system is re-dispatched to utilize the cheap generation capacity available at Node 1, meaning that the power flow from Node 3 to Node 2 (K_{23}) decreases to zero as K increases.

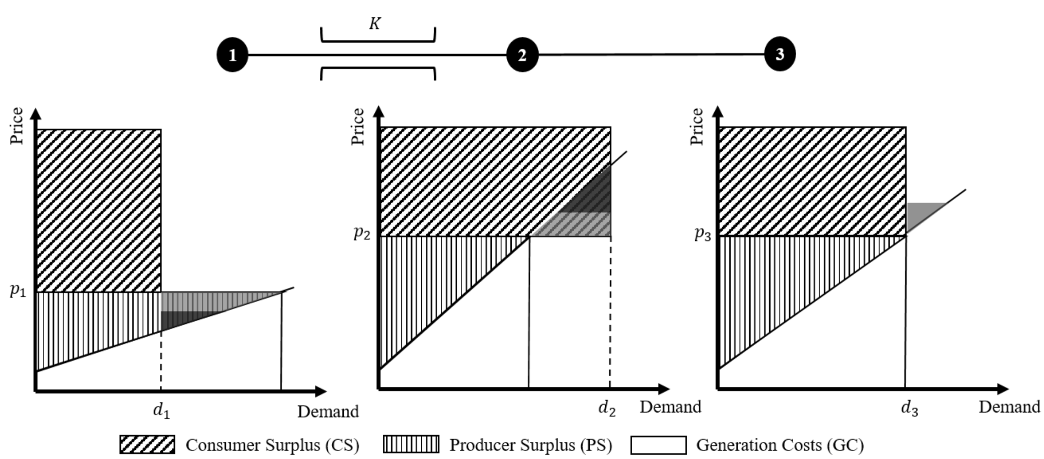

Figure 2: Three-node example where new transmission capacity is added between Node 1 (low price) and Node 2 (high price). Dark shaded areas illustrate the case where it already exists some capacity between Node 1 and 2, while the light shaded areas are the final effects when new capacity is added.

[7]By definition, $a_2 d_2 - a_1 d_1 > 0$, thus $\frac{dW}{dK} + \frac{dCR}{dK} = \frac{K}{2}(a_1 + a_2) + a_2 d_2 - a_1 d_1 > 0$ for $K < K^*$.

The dark shaded areas in Figure 2 show the initial welfare effects of the transmission capacity between Node 1 and 2. When additional transmission capacity (K) is added between Node 1 and Node 2, the system is re-dispatched and welfare increases in these two adjacent nodes (illustrated with the light shaded areas in Figure 2). Simultaneously, as K increases, Node 3 suffers a welfare loss due to less export to Node 2 over K_{23}, since Node 2 imports cheaper electricity from Node 1, i.e. $q_3 = d_3 + K_{23} - K$. Moreover, the CRs accrued between Node 2 and Node 3 decrease due to less trade.

As in the two-node example, the marginal changes in welfare for these three nodes are highly dependent on the slopes of the supply curves at each node. Node 2 has the steepest supply curve and, consequently, experiences the largest change as a result from an increment in the transmission capacity between nodes 1 and 2. Since Node 3's exports are substituted by new trade capacity between nodes 1 and 2, the marginal change in welfare in Node 3 becomes negative, despite the fact that Node 3 has medium-priced generation resources ($a_1 \leq a_3 \leq a_2$). This results in $\frac{dW_2}{dK} \geq \frac{dW_1}{dK} \geq \frac{dW_3}{dK}$, where $\frac{dW_3}{dK} = a_3(K - K_{23}) \leq 0$ as long as the new capacity is lower than, or equal to, the existing capacity between node 2 and 3 ($K \leq K_{23}$).

The three-node system demonstrates that net benefits might not only be unevenly distributed among nodes, or regions, but potentially negative in cases where a new transmission line leads to lower utilization of other, existing lines. This means that the value of some existing transmission rights can potentially decrease to zero after a voluntary, bilateral investment between two nodes elsewhere in the system. This example illustrates why third-party countries should be considered if the approval to build international transmission interconnections requires a broad consensus among all countries in a region, as in the spirit of Regulation (EU) No 347/2013 (EUL, 2013).

5. PROPOSED METHODOLOGY

5.1 Transmission and Generation Planning Model

We use a planning model based on previous work by Trötscher and Korpås (2011), Munoz et al. (2014) and Svendsen and Spro (2016) which has been customized for offshore grid applications (Kristiansen et al., 2017, 2018). To this end, we only provide a high-level overview of its most relevant features supplemented with a detailed description of all variables, parameters, constraints, and its objective function in the Online Appendix. This model captures the problem of a central transmission planner that must select interconnections trying to maximize aggregate welfare for all countries in the region. We assume that all transmission investment decisions are made proactively, anticipating generators' best response to grid developments. In general, finding a solution to this problem involves the implementation of sophisticated algorithms to compute a market equilibrium (Sauma and Oren, 2006). However, since we assume perfect competition in generation investments and operations, inelastic demand, and discrete transmission investments, the above equilibrium problem can be reformulated as a mixed-integer linear optimization program where the objective is to minimize Total System Cost (Samuelson, 1952; Munoz et al., 2014, 2017), where:

Total System Cost = Cost of new transmission interconnections + Cost of new generation capacity + Operational cost of generators + Cost of CO_2 emissions + Cost of curtailed demand

This is subject a series of constraints, some of which include:

- **Supply-demand balance** at each bus in the network in every period. These restrictions take into account imports and exports of power through existing transmission lines and new interconnections. The Lagrange multipliers of these constraints define long-term electricity prices when transmission investments are fixed to their optimal levels.
- **Maximum generation limits**, considering both existing and new generating capacity. We capture the variability of hydro, wind, and solar resources using hourly availability factors from

historical data for each different location in the network. This means that we are able to account for a variety of power flow patterns in the system, while also capturing synergistic effects of the geographical flexibility provided by grid expansion.

- **Thermal limits** on existing transmission lines and on new transmission interconnections.
- **Discrete transmission investment alternatives**, i.e. a transmission line can be built or not built. Additionally, the number of lines per corridor is also determined in order to calculate realistic costs for bulky capacity levels (e.g. related to transformers and power electronics (Härtel et al., 2017b)).

5.2 Computing the Shapley Value

We use the Shapley Value to calculate a fair allocation of net benefits based on each country's contribution to value-creation in transmission interconnections. This mechanism has been used before in different contexts, including problems of maintenance cost allocation at airports (Littlechild and Owen, 1973), as a splitting rule of remaining assets under bankruptcy (O'Neill, 1982), and as a metric to determine the contribution of different energy policies towards a social goal in the context of a combined set of regulations (Murphy and Rosenthal, 2006).

We define a characteristic function, $v(S)$, as the difference in net benefits (i.e., sum of consumer surplus, consumer surplus, and congestion rents) that result from solving the planning problem described in Section 5.1 under the support of coalition S towards the development of new transmission infrastructure and a Base Case, where no transmission projects are developed. We assume that under coalition S, the only transmission interconnections that can be developed are those that are directly connected to host countries that have the power to veto the construction of any lines. For instance, when computing $v(S)$, an interconnection that goes from country A to country B is considered a candidate investment alternative only if $A \in S$ and $B \in S$. If there is no cooperative agreement among host countries and no transmission interconnections can be built, the value function is $v(\emptyset) = 0$. On the other hand, if N is the set that represents the grand coalition (i.e., when all countries reach a cooperative agreement), then $v(N)$ is equal to the total net benefits that would result when considering all transmission interconnections as investment alternatives. Under perfect competition, $v(N)$ is also equal to the welfare gains or net benefits that result from these transmission projects. Following the spirit of Regulation (EU) No 347/2013 (EUL, 2013), we assume that third-party countries will be included in the negotiations. However, for a different application these could be excluded from the computation of the SV by only considering net benefits for host countries in the value function.

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

In Equation (1) above, $\phi_i(N, v)$ denotes the resulting payoff to each country i under the SV. The expression $[v(S \cup i) - v(S)]$ is the increment in net benefits that results when country i joins the coalition S (i.e., its incremental contribution), which could be formed in $|S|!$ different ways prior to country i joining it. Also, there are $(|N| - |S| - 1)!$ ways the remaining countries could join the same coalition. The product of these expressions summed over all combinations of subsets excluding i ($S \subseteq N \setminus \{i\}$) and divided by $|N|!$ can be interpreted as the average incremental contribution of country i to the grand coalition. The n-tuple $(\phi_1(N, v), \phi_2(N, v), ..., \phi_n(N, v))$ is the final allocation of net benefits for all countries under the SV if $n = |N|$.

The SV is the only allocation that satisfies the properties of efficiency (all benefits are distributed among countries), symmetry (countries with the same average incremental contribution receive the same allocation of benefits), linearity, and zero player (countries that do not have veto power get zero net benefits) (Narahari, 2014). In economics, these properties provide an axiomatic definition of fairness (Myerson, 1977). It has been also demonstrated that, under certain conditions, a process of decentralized sequential bargaining among agents converges to the SV (Gul, 1989).

6. CASE STUDY: NORTH SEA OFFSHORE GRID

We study a portfolio of three transmission interconnections that are planned in the North Sea area, surrounded by six countries in total: Norway (NO), Denmark (DK), Germany (DE), The Netherlands (NL), Belgium (BE), and Great Britain (GB) (see Figure 3). Table 2 summarizes the main characteristics of the three transmission investment alternatives: the North Sea Link (NO-GB), the NordLink (NO-DE), and the Viking (DK-GB) (dashed lines in Figure 3). We assume that, if built, these transmission interconnections will be in operation by 2030 under ENTSO-E's scenario Vision 4 (ENTSO-E, 2016).[8] We consider a planning horizon of 30 years with a discount rate of 5%. An overview of key input data can be found in Table 6 in the Online Appendix.

Table 2: Investment alternatives in transmission interconnections. The cost item includes the net present value of investment, operation and maintenance expenses based on estimates from Härtel et al. (2017b).

Project	From	To	Capacity [MW]	Cost [bn€]
North Sea Link	NO	GB	1400	2.73
NordLink	NO	DE	1400	2.16
Viking	DK	GB	1400	2.50

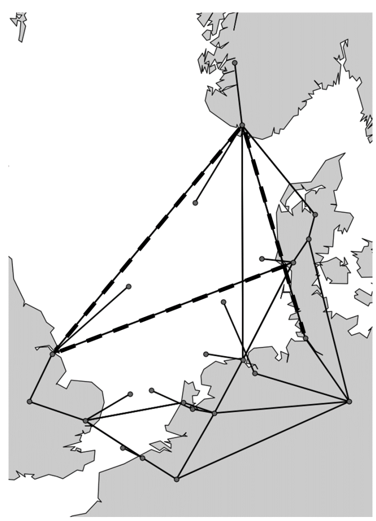

Figure 3: Illustration of the North Sea 2030 case study including all transmission lines that are scheduled to be in operation by year 2030. Candidate branches are shown as dashed lines.

6.1 Computing net benefits for all portfolios of transmission interconnections

We solve the planning problem for the eight possible combinations of investments in transmission interconnections (i.e., 2^3). Table 3 shows the difference in net benefits in equilibrium for each portfolio with respect to the Base Case, where no transmission interconnections are built. Note that all portfolios

[8]ENTSO-E's Vision 4 is a top-down scenario developed at an European level and it is designed to meet the objectives of the European Commission on market integration and on climate-change mitigation. It is considered the most ambitious scenario in terms of investments in renewable generation capacity.

result in positive net benefits with respect to the Base Case, but it is the portfolio that includes all three interconnections (1,1,1) that results in the greatest welfare gains (€25.3bn). Therefore, building the three interconnections is the socially-optimal plan from a central planner's perspective and it is equivalent to what could be achieved under full cooperation among all countries.

Table 3: Aggregate results for the eight possible portfolios of transmission interconnections. Each tuple denotes binary investment decisions (1 if it is built, 0 otherwise) in the following order (North Sea Link, NordLink, Viking). All values for portfolios other than the Base Case are measured relative to the Base Case (0,0,0). Net benefits are in net present value for the 30-year planning horizon and normalized to zero for the Base Case.

	Net benefits [bn€]	Average price [€/MWh]	Cost of CO_2 emissions [bn€]	Transmission investment [bn€]	Generation investment [bn€]	Renewables % of generation
Base case	0	68.92	183.15	0	1.34	58.55
(0, 0, 1)	6.1	-0.12	-1.50	2.50	-0.02	0.17
(0, 1, 0)	8.8	-0.16	-8.90	2.16	-0.00	0.27
(0, 1, 1)	15.0	-0.31	-10.40	4.66	-0.02	0.46
(1, 0, 0)	11.2	-0.25	-3.11	2.73	-0.02	0.24
(1, 0, 1)	16.5	-0.40	-4.91	5.23	-0.02	0.52
(1, 1, 0)	19.1	-0.42	-11.99	4.89	-0.02	0.52
(1, 1, 1)	25.3	-0.55	-13.84	7.40	-0.02	0.81

We compute the average price of electricity for each transmission portfolio as a load-weighted average for all operating hours and across all regions. The social cost of carbon emissions is equal to the value of the carbon tax (76 €/ton, in line with ENTSO-E (2016)) times total emissions in the system (ton CO_2). Investment costs are separated into transmission investments and generation investments. We also include the resulting share of generation from renewable energy technologies as a fraction of total energy production. Note that the share of renewables is relatively high for all transmission configurations because we assume that the amount of installed generating capacity is equal to what it is outlined in ENTSO-E Vision 4, a very ambitious scenario for 2030 in terms of renewable penetration. While here we only focus on net benetifs from transmission interconnections, it is worth mentioning that there are also other potential benefits from these projects that could be relevant for countries in the region. Some of these include reductions in average electricity prices and carbon emissions, as well as higher shares of generation from renewable energy technologies with respect to a Base Case without interconnections.

6.2 A fair allocation of net benefits under the Shapley Value

We compute the Shapley Value using the methodology described in Section 5.2 and the results described in Table 3. Recall that the SV supports the socially-optimal portfolio of transmission interconnections under the assumption that all countries will reach a cooperative agreement. The SV also provides a fair allocation of net benefits for all countries in the region considering their average incremental contribution to the grand coalition. Figure 4 shows the final allocation of net benefits for all countries in the NSOG with respect to the Base Case (i.e., when no transmission interconnections are built).

First of all, note that the SV suggests that Norway should receive the largest fraction of net benefits (nearly €10bn) among all six countries as a result of the three new transmission interconnections. This is because Norway has the power to veto two of the proposed interconnections: the North Sea Link (NO-GB) and the NordLink (NO-DE). Similarly, Great Britain should receive the second largest fraction of net benefits (nearly €8bn) because it could unilaterally veto the development of the North Sea Link (NO-GB) and the Viking (DK-GB). The economic intuition behind the difference in the allocation of net benefits for Norway and Great Britain can be explained by the difference in net benefits that result from the construction of the three candidate projects. While the SV considers all the possible sequences of development of these interconnections, one can gain some insights by,

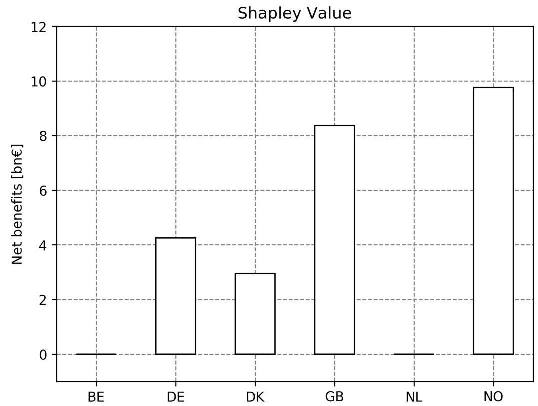

Figure 4: A fair allocation of net benefits per country under the Shapley Value. Values are measured with respect to the Base Case (0,0,0).

for instance, comparing the incremental net benefit of developing just one of the three projects with respect to the Base Case (0,0,0). The nef benefits that result from developing either the North Sea Link (1,0,0), the NordLink (0,1,0), or the Viking (0,0,1) with respect to the Base Case are €11.1bn, €8.8bn, and €6.1bn, respectively. Based on these numbers, Norway should be allocated a larger fraction of net benefits than Great Britain because it has the power to veto the construction of the two most valuable interconnections, the North Sea Link and the NordLink, whereas Great Britain could only block a set of two less valuable projects, the NordLink and the Viking.

Interestingly, one would reach the same conclusion when considering the incremental value of adding any of the three projects when the other two interconnections are already in place. For instance, the value of adding the North Sea Link is equal to the incremental net benefit of going from portfolio (0,1,1) to (1,1,1). The net benefits that result from adding either the North Sea Link, the NordLink, or the Viking with respect to scenario where the other two projects have been already developed are equal to €10.3bn, €8.8bn, and €6.2bn. Again, Norway has the power to veto projects that are more valuable than the projects that could be blocked by Great Britain and, consequently, Norway should receive a larger fraction of the net benefits that result from the development of the three interconnections. We want to highlight that the incremental value that results from a country joining a coalition also reflects the value of the resources that become available for the rest of countries in a system. For instance, the system as a whole will benefit from new transmission interconnections to Norway's flexible hydropower resources that cause no direct carbon emissions.

Note that both Denmark and Germany should also receive positive net benefits based on their average incremental contribution to the grand coalition. However, the share of net benefits allocated to these countries is nearly half of what should be allocated to Norway and Great Britain. What explains this difference is that Denmark could only veto the Viking and Germany could only block the construction of the NordLink, therefore, their incremental contribution to the cooperative agreement is lower than the one by Norway and Great Britain. The difference in allocated net benefits between Denmark and Germany is rooted in the economic value of the project that they could unilaterally block. The Viking has a lower incremental value for the system than the NordLink, which means that Germany should be allocated a larger fraction of net benefits than DK.

Third-party countries, Belgium and the Netherlands receive zero net benefits as a result of the new transmission interconnections because they have no power to veto the construction of any of the three lines (i.e., their incremental value to the grand coalition is zero). This means that, under the SV, third-party countries are indifferent to the development of the three proposed transmission interconnections.

6.3 Comparing final allocations of net benefits under the Shapley Value relative to two conventional mechanisms: the Equal Share Principle and the Positive Net Benefit Differential

Here we consider two conventional allocation mechanisms that have been used in existing transmission interconnections. The first one divides the capital costs of transmission interconnections and congestion rents between host countries in equal shares (i.e., 50 % to each country). Following the terminology in Jansen et al. (2015), we refer to this allocation mechanism as the Equal Share Principle (ESP). The second mechanism is the Positive Net Benefit Differential (PNBD), which allocates the capital cost of transmission interconnections in proportion to estimated benefits (including congestion rents).[9]

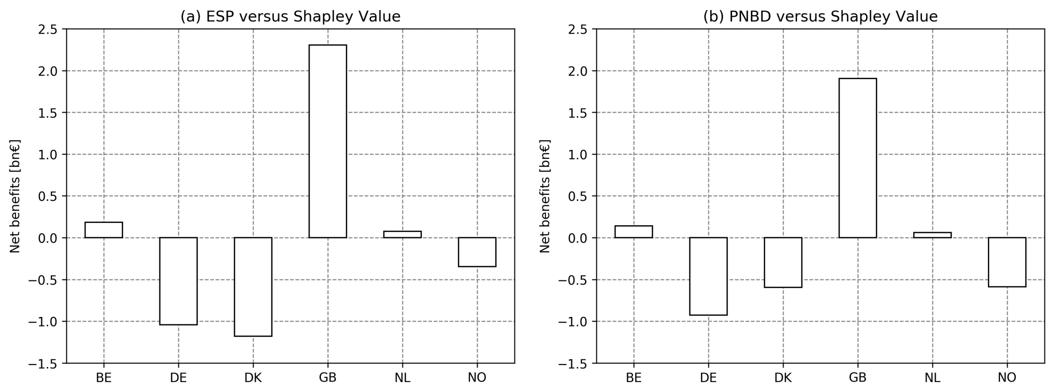

Figure 5: Relative differences of net benefits per country when comparing the (a) Equal Share Priciple (ESP) and the (b) Positive Net Benefit Differential (PNBD) with respect to the Shapley Value. Positive values indicate that countries are overcompensated relative the SV allocation.

Figure 5 (a) shows the relative difference between the final allocation of net benefits under the ESP and the SV and Figure 5 (b) shows the difference between the final allocation of net benefits between the PNBD and the SV. Note that under the ESP, Great Britain would receive €2.3bn more of net benefits than under the SV. Since Norway will receive nearly €0.25bn less of net benefits than under the SV, under the ESP, Great Britain will end up receiving almost €1bn more net benefits than Norway, even though Norway has the power to veto the two most valuable proposed interconnections. This could complicate negotiations because Norway could refuse to accept the construction the North Sea Link and the NordLink unless it receives a larger share of net benefits than Great Britain. Moreover, the negotiations with both Germany and Denmark could also become difficult because under the ESP their final shares of net benefits are nearly 25% and 33% lower than their average incremental contribution to the grand coalition, respectively. Again, this is because the ESP ignores the power of host countries to veto the construction of new transmission interconnections. Belgium and the Netherlands will free ride on the rest of the countries in the NSOG because they will bear no costs, even though the new interconnections will provide positive net benefits to these two third-party countries.

Splitting transmission costs in proportion to estimated net benefits, as in the PNBD, will result in an allocation that is slightly closer the SV (Figure 5 (b)). Great Britain, for instance, will bear a larger share of transmission costs and, consequently, receive a lower share of net benefits than under the ESP (nearly €0.35bn less). Likewise, both Germany and Denmark will bear a lower share of transmission costs and end up with a larger share of net benefits than under the ESP. However, the change will be rather small with respect to the ESP. Net benefits for Great Britain will remain larger

[9] Here we consider the first variant of the PNBD described in Jansen et al. (2015) which is based on the beneficiary pays principle (Hogan, 2018), meaning that transmission costs are distributed among all countries in the interconnected system. The second variant limits the distribution of costs to host countries only (Konstantelos et al., 2017b).

than for Norway, and both Germany and Denmark will continue to receive a disproportionately small fraction of net benefits compared to their average incremental contribution to the grand coalition. Third-party countries will still free ride on host countries, as under the ESP, because their allocated share of transmission costs is too small compared to what it would be fair under the SV. Furthermore, Norway will be worse off under the PNBD because it will be responsible for bearing a larger share of transmission costs than under the ESP. While this is in line with cost-allocation rules used elsewhere, ignoring the power of this country to veto the two most valuable proposed projects could lead to failure to reach a cooperative agreement among all countries in the region. These two examples illustrate why more sophisticated mechanisms for allocating benefits and costs, such as the SV, could provide stronger incentives for cooperation than conventional mechanisms such as the ESP and the PNBD.[10]

6.4 Achieving the Shapley Value through a set of Power Purchase Agreements

In the previous section we showed that there are important differences between the final allocations of net benefits under the SV and the two conventional mechanisms. One alternative to achieve the SV is to initially support the development of new transmission interconnections using one of the conventional allocation approaches and then implement a mechanism of side payments that would result in the desired allocation of net benefits over the planning horizon. Figure 6 shows the side payments required to achieve the SV in our case study, assuming that interconnections will be initially supported using the ESP. However, it is not clear if such mechanism would be implementable in practice. The main limitation of this approach is that it would involve large transfers of net benefits among countries—ranging from €80m to €2300m in our case study—*before* these benefits are even realized.

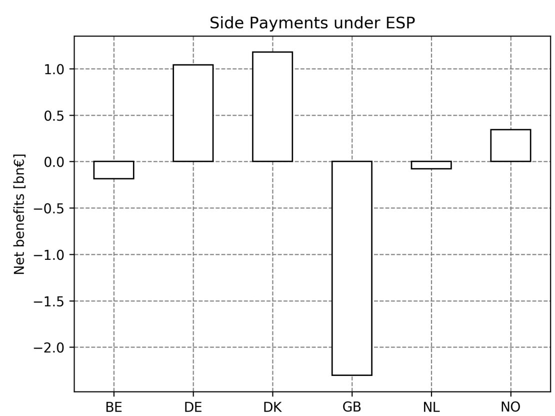

Figure 6: Side payments required to achieve the allocation of net benefits under the Shapley Value if interconnections are initially supported through the ESP. Positive values represent compensations while negative values are payments to the cooperative interconnection fund. All side payments add up to zero.

One alternative to achieve the SV as countries trade power over time would be the implementation of a set of Power Purchase Agreements (PPAs) and a *cooperative interconnection fund*. Under this mechanism, the cost of new transmission interconnections and congestion rents could be initially divided through a conventional mechanism, such as the ESP or the PNBD. A coordinating organization (e.g., ENTSO-E or ACER) could then estimate the required side payments to achieve a

[10] In fact, in Sections 8.4 and 8.5 in the Appendix we verify that neither the ESP nor the PNBD are in the core of the game because third-party countries receive positive net benefits. This means that both allocation rules are unstable. We also verify that, if the planning problem is considered a non-cooperative game, then the efficient solution is a Nash equilibrium (see Table 8 in the Online Appendix). This is because host countries do not have incentives to deviate from the Nash equilibrium and veto transmission projects. However, this ignores bargaining considerations, such as the power of Norway to block the construction of the two most valuable transmission lines if it receives a smaller fraction of net benefits than Great Britain.

fair allocation of net benefits under the SV. This set of side payments could be used as a basis for defining a set of PPAs, as contracts for differences, between the interconnection fund and each country in the region.

Let's consider the following contractual agreement. Say PPA_A is the (fixed) contract price for country A, L_A is the set of transmission interconnections to neighboring countries of A (both new and existing), $P^{spot}_{l,t}$ is the hourly price at the node where line l is connected to country A (border node), $f^{exp}_{l,t}$ and $f^{imp}_{l,t}$ are the hourly power flows that, respectively, go out and into country A through line l (both are nonnegative), and $loss_l$ is a loss factor. If country A sells its power (i.e., if $f^{exp}_{l,t} > 0$ and $f^{imp}_{l,t} = 0$) at a fixed price equal to PPA_A but collects $P^{spot}_{l,t}$ for every MWh of power exported through line l, then this country must receive a side payment from the interconnection fund equal to $(PPA_A - P^{spot}_{l,t}) \cdot f^{exp}_{l,t}$ if $PPA_A > P^{spot}_{l,t}$. On the other hand, if $PPA_A < P^{spot}_{l,t}$, then country A must pay a compensation to the interconnection fund equal to $(P^{spot}_{l,t} - PPA_A) \cdot f^{exp}_{l,t}$. The opposite is true if country A imports power at a certain hour (i.e., if $f^{imp}_{l,t} > 0$ and $f^{exp}_{l,t} = 0$). Summing over all transmission interconnections connected to country A, L_A, and over all representative hours in the planning period T[11] (e.g., 8760 hours in a representative year), we can compute the side payment to country A, denoted SP_A, as follows:

$$SP_A = a \cdot \sum_{l \in L_A} \sum_{t \in T} (PPA_A - P^{spot}_{l,t}) \cdot (f^{exp}_{l,t} - f^{imp}_{l,t} \cdot (1 - loss_l)) \tag{2}$$

If $SP_A > 0$, country A will receive a side payment , otherwise, if $SP_A < 0$, A will pay an economic compensation to the interconnection fund. Note that given an estimate of SP_A from Figure 6, it is possible to find the value of PPA_A such that, over time, country A will ultimately achieve a desired allocation of net benefits. This could be applied to all countries in the region to define the set of PPAs that achieve the desired final allocation of net benefits under the SV. Note that if C denotes the set of countries in the region, then:

$$\sum_{c \in C} SP_c = 0 \tag{3}$$

This is true because, by construction, side payments are only welfare transfers among countries to achieve the SV (see Figure 6). In the mechanism design literature this property is known as *budget balancedness* (Narahari, 2014).

Table 4: Summary of PPAs per country to achieve the SV. Average prices are weighted by demand. The PPA profit per country is equal to the net compensation received from the cooperative fund every year required to achieve the side payments in Figure 6.

	Net export TWh/yr	PPA €/MWh	Average price €/MWh	PPA profit m€/yr
NO	29.0	20.6	19.9	22.5
DK	8.4	72.4	63.3	76.7
DE	6.1	90.3	79.3	67.8
NL	-25.5	85.4	85.2	-5.0
BE	-22.0	89.3	88.8	-12.0
GB	3.9	35.4	73.8	-149.9

Table 4 above shows values of PPAs to achieve the SV based on the side payments from Figure 6, assuming that interconnections will be initially funded through the ESP. We include the average load-weighted local price of electricity for each country as a reference to give the reader an idea if the PPA determines that power will be exported (or imported) at a price that is, on average,

[11] The parameter a denotes an annuity factor used to compute the discounted sum of annual side payments over the 30-year planning horizon.

higher or lower than the local price of electricity.[12] Norway, for instance, is a net exporter and would need a PPA with a fixed price of 20.6€/MWh—0.7€/MWh higher than the local average price—to receive the desired side payment of €22.5m per year. The Netherlands on the other hand, is a net importer of power and would need to buy power through the existing transmission interconnections at a fixed price of 85.4€/MWh—0.2€/MWh higher than the local average price—to achieve the desired payment of €5m per year to the cooperative interconnection fund.

The main advantage of using PPAs to achieve the SV is that net benefits will be redistributed as countries trade power over time, not prior to their realization. Of course, the set of PPAs proposed here is only one possible alternative to achieve the SV, more elaborate contractual agreements could be used to attain the same objective. For instance, if a country has zero net exports (e.g., annual inflows = annual outflows) it might be more convenient to use a PPA with different base prices for imports and exports for that specific country.

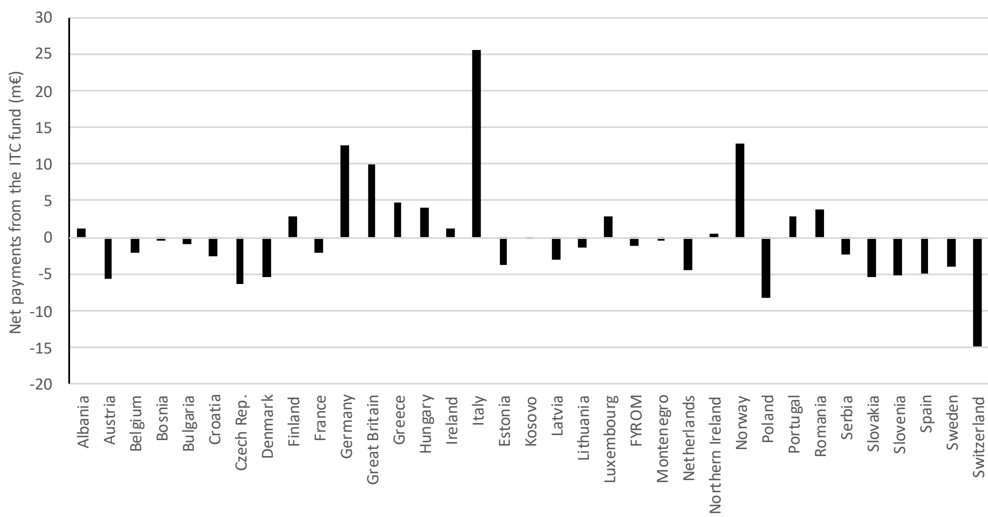

Figure 7: Annual net compensations from the ITC fund per country in 2016. Positive values indicate compensations from the fund to individual countries and negative values are contributions to the fund. Data retrieved from ACER (2017).

Finally, we want to highlight that the proposed mechanism to redistribute net benefits and costs among countries in the NSOG is akin to the existing mechanism for inter-TSO compensations in the EU. The inter-TSO compensation (ITC) mechanism is designed to compensate countries for the cost of making infrastructure available and for the cost of transmission losses for hosting cross-border flows (Hirschhausenm et al., 2012). Figure 7 shows net payments to each country in the EU from the ITC fund in 2016 (ACER, 2017). The ITC fund in 2016 was approximately €258m and, for the same year, net payments from the fund to individual countries were equal to €170m (i.e., sum of all positive values in Figure 7). The total amount of annual compensation payments to the interconnection fund needed to achieve the SV in our case is equal to €166.9m (i.e., sum of all positive PPA profits per year in Table 4). With the exception of the required payment from Great Britain to the fund (€149.9m per year), the required annual net payments to the interconnection fund per country displayed in Table 4 and the current annual net compensations to the ITC fund in Figure 7 are within the same order of magnitude.

[12] Note that the difference between the fixed price of the PPAs and the average load-weighted local prices times net export flows is not equal to the desired side payment. This is because the actual side payments are computed using hourly spot prices that are not weighted by demand. In Table 4 we only provide average load-weighted electricity prices for illustrative purposes.

6.5 Stability of the Shapley Value

The main goal of our article is to describe how the Shapley Value could be used to determine a fair allocation of net benefits among countries that reach a cooperative agreement to develop a set of transmission interconnections. While the SV is the only allocation that is based on the average incremental contribution to the system and that satisfies a set of desirable properties, there is no guarantee that the solution will be stable (Maskin, 2003). This is because some countries could be better off by forming subcoalitions and potentially block the construction of new transmission interconnections.

In cooperative games, an allocation is said to be in *the core* of the game if agents have no incentives to deviate from the grand coalition and form subcoalitions. It has been demonstrated that if a cooperative game is convex, then the SV is in the core (Narahari, 2014). A game is convex if the incentives to join a coalition are weakly increasing on the size of the coalition. Equation 4 shows the property of convexity of a cooperative game, where the incremental value for country i to join coalition T is higher than or equal to the incremental value of joining coalition S, where coalition S is formed by a subgroup of the countries that form coalition T (i.e., $S \subseteq T$).

$$v(S \cup \{i\}) - v(S) \leq v(T \cup \{i\}) - v(T) \qquad \forall S \subseteq T \subseteq N \backslash \{i\}, \forall i \in N \tag{4}$$

While checking for convexity in a generic cooperative game might seem difficult, in our case it is actually very simple. It is mostly a matter of verifying that the incremental value of adding a new transmission interconnection when other lines are already in place is greater or equal than the value of adding the line when at least one of the other lines was not developed. For instance, the incremental value of adding NO to the coalition $S = \{GB\}$ is $v(GB, NO) - v(GB)$ =€11.2bn, equal to the value of going from portfolio (0,0,0) (Base Case) to (1,0,0) in Table 3. The incremental value of adding NO to a larger coalition than S, say $T = \{GB, DE\}$, is $v(GB, DE, NO) - v(GB, DE)$ =€19.1bn, which is equal to the value of going from portfolio (0,0,0) to (1,1,0). Consequently, the value of adding NO to a coalition T is higher than the value of adding NO to $S \subseteq T$. Since this is also true for the rest of the countries in the NSOG and all possible subsets of the grand coalition, the cooperative game is convex and the final allocation of net benefits computed using the SV is in the core. Consequently, the proposed allocation is not only fair, but also stable because countries have no incentive to deviate from the grand coalition. Although we do not provide a general proof that cooperative games of international transmission interconnections are always convex, verifying whether this property holds, or not, in real-world applications should be relatively simple since these usually have a very limited number of transmission investment alternatives.

Another alternative to evaluate if an allocation rule is in the core of the game is to explicitly write the set of linear inequalities that define the core. These include individual, coalitional, and collective rationality constraints. We include these constraints in Section 8.4 of the Appendix.

7. CONCLUSIONS

In this paper, we present a mechanism for allocating the benefits and costs that result from the development of international transmission interconnections under a cooperative agreement. We focus on this subject inspired by the goal of the EU Commission to integrate markets in order to increase the economic efficiency and security of supply of the electric power system. The integration of markets can also result in reductions of greenhouse gas emissions. Unlike federal rules for interregional transmission planning enforced by FERC in the U.S. (FERC, 2012), the EU Commission has no legal power to impose the development of new transmission interconnections that are deemed efficient between countries in the EU. This means that these projects will only be developed if all involved countries reach an agreement on how to divide the resulting benefits and costs in a fair manner.

Our proposed mechanism is based on the Shapley Value from cooperative game theory and a detailed planning model that takes into account generators' response to transmission investments. The main advantage of the Shapley Value is that it provides a unique allocation of net benefits based on each country's average incremental contribution to the grand coalition. Furthermore, the Shapley Value is the only allocation that fulfills a series of desirable properties that, in the economic literature, are referred to as the axiomatic definition of fairness (Myerson, 1977). This is an improvement over conventional allocation methods because the proposed mechanism explicitly considers the power of each country in the region to veto the construction of new transmission interconnections. Consequently, countries that have the power to block the development of highly valuable transmission projects are allocated a larger fraction of net benefits than countries that can only block projects of low incremental value to the system. In our case study, both Norway and Great Britain are allocated a larger fraction of net benefits than the rest of countries in the NSOG because they can each block two of the three proposed interconnections. In contrast, under the Shapley Value, Belgium and the Netherlands receive zero net benefits from new transmission interconnections because they have no power to veto any of the three proposed projects.

We verify that under two conventional allocation methods, the Equal Share Principle and the Positive Net Benefit Differential, some countries receive a fraction of net benefits that is much larger than their average incremental contribution to the system. The best example is Great Britain, which is allocated nearly €2bn of net benefits in excess of its actual incremental contribution under both conventional allocation mechanisms. In fact, under these allocation rules, Great Britain ends up with a larger share of net benefits than Norway, even though the latter can veto the two most valuable transmission interconnections. The opposite is true for Denmark and Germany, which are undercompensated by nearly €1bn each. Also, under both conventional methods, Belgium and the Netherlands (third-party countries) end up free riding on the rest of the system because they are not required to bear any costs of new infrastructure. We believe that these discrepancies between the actual incremental contribution of each country to the cooperative agreement and the final allocation of benefits and costs under conventional mechanisms could make negotiations difficult or create political tension among countries in the region. The mechanism we propose in this article can help organizations that foster collaboration among countries, such as ENTSO-E, to find a fair manner to split the benefits and costs that result from international transmission interconnections.

We also show that the final allocation of net benefits under the Shapley Value can be used as a basis for defining a set of Power Purchase Agreements, such that countries achieve the desired final allocation of net benefits as they trade power over time. This is similar to the current mechanism for compensations among TSOs in the EU (i.e., the ITC fund), which was implemented to compensate countries for the cost of making their transmission infrastructure available to host cross-border flows and the cost of the resulting transmission losses.

While there is no guarantee that the Shapley Value value will always result in a stable allocation of net benefits (i.e., the Shapley Value is not always in the core of a cooperative game), there is a general result that proves that the Shapley Value is stable if the game is convex. We show that this property can be easily verified in real-world interconnection planning problems because investment alternatives are often limited. In our case study, the final allocation of net benefits under the Shapley Value is convex and, consequently, countries do not have incentives to leave the grand coalition or to veto the construction of any of the three transmission interconnections. However, for some cooperative games, the Shapley Value might not be in the core (e.g., if the game is nonconvex) or the core might be an empty set. It is worth highlighting that an empty core does not imply that the grand coalition will fail to form. Maskin (2003), for instance, shows an example of a cooperative game with an empty core where the grand coalition still forms and agents achieve the Shapley Value through an iterative bargaining process with binding contracts. The author also provides a generalization of the Shapley Value to cooperative games when coalitions exert externalities on other coalitions (e.g., pollution games). The approach proposed by Maskin (2003) is a good alternative to the mechanism we describe in this paper if, for some application, countries prefer to block some of the proposed transmission interconnections. Another alternative to the Shapley Value if a game is nonconvex is the Nucleoulus (Schmeidler, 1969). This approach also provides a unique allocation of net benefits based on bargaining considerations, aiming at minimizing the incentives of the most dissatisfied agent in the game to withdraw from the grand coalition (Narahari, 2014). These alternatives should be explored in future studies.

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8. APPENDIX

Here we present a detailed description of the planning model, a summary of the input data used in our case study of the NSOG, and supplementing results that support our discussions.

8.1 Detailed description of the planning model

Table 5: Notation for the generation and transmission planning model (PowerGIM).

Sets & Mappings	
$n \in N$	: nodes
$i \in G$	: generators
$b \in B$	: branches
$l \in L$	: loads, demand, consumers
$t \in T$	: time steps, hour
$i \in G_n, l \in L_n$	: generators/load at node n
$n \in B_n^{in}, B_n^{out}$	: branch in/out at node n
$n(i), n(l)$	: node mapping to generator i/load unit l
Parameters	
a	: annuity factor
ω_t	: weighting factor for hour t (number of hours in a sample/cluster) [h]
$VOLL$	: value of lost load (cost of load shedding) [€/MWh]
MC_i	: marginal cost of generation, generator i [€/MWh]
$CO2_i$	: CO_2 emission costs, generator i [€/MWh]
D_{lt}	: demand at load l, hour t [MW]
B, B^d, B^{dp}	: branch mobilization, fixed- and variable cost [€,€/km,€/kmMW]
CS_b, CS_b^p	: onshore/offshore switchgear (fixed and variable cost), branch b [€,€/MW]
CX_i	: capital cost for generator capacity, generator i [€/MW]
CZ_n	: onshore/offshore node costs (e.g. platform costs), node n [€]
P_i^e	: existing generation capacity, generator i [MW]
γ_{it}	: factor for available generator capacity, generator i, hour t
P_b^e	: existing branch capacity, branch b [MW]
$P_b^{n,max}$	: maximum new branch capacity, branch b [MW]
D_b	: distance/length, branch b [km]
l_b	: transmission losses (fixed + variable w.r.t. distance), branch b
E_i	: yearly disposable energy (e.g. energy storage), generator i [MWh]
M	: a sufficiently large number
Primal variables	
y_b^{num}	: number of new transmission lines/cables, branch b
y_b^{cap}	: new transmission capacity, branch b [MW]
z_n	: new platform/station, node n
x_i	: new generation capacity, generator i [MW]
g_{it}	: power generation dispatch, generator i, hour t [MW]
f_{bt}	: power flow, branch b, hour t [MW]
s_{nt}	: load shedding, node n, hour t [MW]

We minimize the net present value (NPV) of total system costs and find the socially optimal solution that would be attained under full cooperation among all involved countries. Total costs (1a) include investment costs (1b) and operational costs (1c). Operational costs are calculated for one representative year, multiplied with an annuity factor a in order to convert annual costs to NPV.

Transmission infrastructure investments are represented with both fixed (1d) and variable costs (1e). We determine fixed costs based on mobilization costs B and cable distance $B^d D_j$, in addition to voltage transformers and/or power electronics needed at each end of the cable (CL is the cost for land-based stations and CS is the cost for offshore-based stations). Fixed costs are multiplied by an integer variable that reflects the number of cables, y_b^{num}. Moreover, in the expression that describes the variable costs (1e) there is a power-distance dependent cost parameter $B^{dp} D_j$ and a power dependent cost parameter for the end-points of the branch (CL^p is the cost for land-based stations and CS^p is the cost for offshore-based stations), which is multiplied by new branch capacity, y_b^{cap}. In cases where a node facility does not exist, e.g. an offshore node/platform, a binary variable, z_n, is used to reflect installation costs C_n^{bus} for such a node facility which is forced to be implemented by restriction (1l). We ignore Kirchhoff's voltage laws since the majority of the system consist of high voltage direct current (HVDC) branches that are fully controllable, yielding a transport model with no loop flows as shown in Equation (1j) and (1k). However, linear losses for power flows f_b are incorporated to reflect both the transmission distance and the use of necessary voltage transformers and power electronics (1f).

The variability of wind, solar, hydropower, and load is incorporated using full-year hourly profiles from both historical and simulated weather data, where the latter source is particularly relevant for offshore locations with limited historical information (Kristiansen et al., 2016). We model the hourly variability of these resources using factors γ_{it} in (1h) ranging from 0 to 100% inflow/availability and multiplied by the maximum existing capacity, P_i^e, plus any additional capacity investments, x_i (1c). We use an agglomerative hierarchical clustering technique (Härtel et al., 2017a) in order to reduce the hourly resolution from 8760 hours to 500 representative ones, where each hour is weighted by ω_t (number of hours in a cluster) in (1c) and (1i), while maintaining multi-variate correlations between the different technologies and geographical coordinates.

Variables g_{it} denote generator dispatch levels with marginal cost MC_i and emission cost CO_2 for technologies that use fossil fuels. Load shedding, s_n , is allowed at a cost equivalent to the value of lost load $VOLL$. The market clearing, or energy balance, for each time step is given by Equation (1f) for a projected demand profile, D_{lt}. We determine long-run electricity prices from the dual variables of Equation (1f) after fixing all transmission investment variables (binaries) and resolving the remaining generation investment and dispatch problem that yields a linear program.

$$\min_{x,y,z,g,f,s} \quad IC + a \cdot OC \tag{1a}$$

where

$$IC = \sum_{b \in B} (C_b^{fix} y_b^{num} + C_b^{var} y_b^{cap}) + \sum_{n \in N} CZ_n z_n + \sum_{i \in G} CX_i x_i \tag{1b}$$

$$OC = \sum_{t \in T} \omega_t (\sum_{i \in G} (MC_i + CO2_i) g_{it} + \sum_{n \in N} VOLL s_{nt}) \tag{1c}$$

$$C_b^{fix} = B + B^d D_b + 2CS_b \qquad \forall b \in B \tag{1d}$$

$$C_b^{var} = B^{dp} D_b + 2CS_b^p \qquad \forall b \in B \tag{1e}$$

subject to

$$\sum_{i \in G_n} g_{it} + \sum_{b \in B_n^{in}} f_{bt}(1 - l_b) - \sum_{b \in B_n^{out}} f_{bt} + s_{nt} = \sum_{l \in L_n} D_{lt} \qquad \forall n, t \in N, T \tag{1f}$$

$$s_{nt} \leq \sum_{l \in L_n} D_{lt} \qquad \forall n, t \in N, T \tag{1g}$$

$$P_i^{min} \leq g_{it} \leq \gamma_{it}(P_i^e + x_i) \qquad \forall i, t \in G, T \tag{1h}$$

$$\sum_{t \in T} \omega_t g_{it} \leq E_i \qquad \forall i \in G \tag{1i}$$

$$-(P_b^e + y_b^{cap}) \leq f_{bt} \leq (P_b^e + y_b^{cap}) \qquad \forall b, t \in B, T \tag{1j}$$

$$y_b^{cap} \leq P_b^{n,max} y_b^{num} \qquad \forall b \in B \tag{1k}$$

$$\sum_{b \in B_n} y_b^{num} \leq M z_n \qquad \forall n \in N \tag{1l}$$

$$x_i, y_b^{cap}, g_{it}, s_{nt} \in \mathbb{R}^+, \quad f_{bt} \in \mathbb{R}, \quad y_b^{num} \in \mathbb{Z}^+, \quad z_n \in \{0, 1\}$$

8.2 Summary of input data

Table 6: Input data: Marginal costs, generation capacity and peak load per country (ENTSO-E, 2016). An emission tax of 76 €/tonCO_2 is added on top of marginal costs for thermal generators. The economic lifetime of investments is assumed to be 30 years and the discount rate is 5 %.

	Costs	NO	DK	DE	NL	BE	GB	Sum
	EUR/MWh	MW						
Biomass	50	0	1 720	9 340	5 080	2 500	8 420	26 880
Coal	21	0	410	14 940	0	0	0	15 350
Lignite	10	0	0	9 026	0	0	0	9 026
Natural Gas	65	855	3 746	45 059	14 438	10 040	40 726	114 864
Hydro	-	48 700	9	14 505	38	2 226	5 470	70 948
Nuclear	5	0	0	0	486	0	9 022	9 508
Oil	140	0	735	871	0	0	75	1 681
Solar PV	0	0	1 405	58 990	9 700	4 925	11 915	86 935
Wind Onshore	0	1 771	6 695	76 967	5 495	3 518	27 901	122 347
Wind Offshore	0	724	6 130	20 000	4 500	4 000	30 000	65 354
Total generator capacity	-	52 050	20 850	249 698	39 739	27 209	103 510	493 056
Peak load	-	24 468	6 623	81 369	18 751	13 486	59 578	204 275

8.3 Coalition formation of non-zero countries

Table 7 shows a subset of the $2^6 = 64$ possible coalitions that only includes countries with veto power, i.e. Norway (NO), Denmark (DK), Great Britain (GB), and Germany (DE).

Table 7: Coalition formation of non-zero players, in our case countries, from zero investments (0,0,0) to the cooperative solution (1,1,1) where all countries join the grand coalition.

Coalition	Lines built	Net benefits [bn€]
()	(0,0,0)	0.00
(DE)	(0,0,0)	0.00
(DK)	(0,0,0)	0.00
(GB)	(0,0,0)	0.00
(NO)	(0,0,0)	0.00
(DE,DK)	(0,0,0)	0.00
(DE,GB)	(0,0,0)	0.00
(DE,NO)	(0,1,0)	8.8
(DK,GB)	(0,0,1)	6.1
(DK,NO)	(0,0,0)	0.00
(GB,NO)	(1,0,0)	11.2
(DE,DK,GB)	(0,0,1)	6.1
(DE,DK,NO)	(0,1,0)	8.8
(DE,GB,NO)	(1,1,0)	19.1
(DK,GB,NO)	(1,0,1)	16.5
(DE,DK,GB,NO)	(1,1,1)	25.3

8.4 The core of the cooperative game

We denote x_i the allocation of net benefits that country i will receive from the development of transmission interconnections. The inequalities below define the core of the cooperative game for non-zero players or host countries.

Individual rationality constraints:

$$x_{DE} \geq 0 \quad x_{DK} \geq 0 \quad x_{GB} \geq 0 \quad x_{NO} \geq 0$$

Coalitional rationality constraints:

$$\begin{aligned}
x_{DE} + x_{DK} &\geq 0 \\
x_{DE} + x_{GB} &\geq 0 \\
x_{DE} + x_{NO} &\geq 8.8 \\
x_{DK} + x_{GB} &\geq 6.1 \\
x_{DK} + x_{NO} &\geq 0 \\
x_{GB} + x_{NO} &\geq 11.2 \\
x_{DE} + x_{DK} + x_{GB} &\geq 6.1 \\
x_{DE} + x_{DK} + x_{NO} &\geq 8.8 \\
x_{DE} + x_{GB} + x_{NO} &\geq 19.1 \\
x_{DK} + x_{GB} + x_{NO} &\geq 16.5
\end{aligned}$$

Collective rationality constraint:

$$x_{DE} + x_{DK} + x_{GB} + x_{NO} \geq 25.3$$

A candidate allocation rule x^* is stable if it satisfies all individual, coalitional, and collective rationality constraints.

8.5 Net benefits per country under conventional allocation schemes

Under both the ESP and the PNBD the final allocation of benefits are not part of the core of the cooperative game, as it was defined in Section 8.4. This is because both allocations violate the collective rationality constraints (defined excluding zero players), since third-party countries receive positive net benefits.

Table 8 supports the discussions in Section 6 about the potential stability of these allocation methods when the game is analyzed as a non-cooperative one. It illustrates that the two conventional allocation schemes do, in fact, result in Nash equilibria for our case study in a non-cooperative setting. Note that if, under any of these two mechanisms, countries agree to support the three interconnections (1,1,1), then no country would have incentives to unilaterally block a transmission project. However, note that this is also true for other project portfolios, which makes prediction using concepts from non-cooperative game theory very difficult.

Table 8: Relative net benefits [m€] with respect to the grand coalition (1,1,1). Left side shows the result from an Equal Share cost allocation, while the right part comprise a Positive Net Benefit Differential allocation of costs. The combinations have the following ordering (NorthSeaLink, NordLink, Viking). The most beneficial projects are those with the highest numbers (bold font).

	ESP						**PNBD**					
	NO	DE	DK	BE	NL	GB	NO	DE	DK	BE	NL	GB
(0, 0, 0)	-9 414	-3 202	-1 773	-180	-73	-10 670	-8 679	-3 917	-2 822	-180	-73	-9 641
(0, 0, 1)	-9 402	-2 979	**80**	-158	-77	-6 629	-8 666	-3 694	-601	-158	-77	-5 968
(0, 1, 0)	-3 591	-436	-1 783	-87	-42	-10 591	-3 161	-846	-2 832	-87	-42	-9 563
(0, 1, 1)	-3 578	-71	65	-66	-7	-6 679	-3 377	-644	-519	-66	-7	-5 724
(1, 0, 0)	-5 393	-3 132	-1 768	-117	-89	-3 628	-4 363	-3 847	-2 816	-117	-89	-2 894
(1, 0, 1)	-5 288	-3 016	-17	-63	-32	-8	-4 343	-3 731	-264	-63	-32	-405
(1, 1, 0)	**44**	-382	-1 791	-23	-43	-3 623	**46**	-501	-2 840	-23	-43	-2 845
(1, 1, 1)	0	**0**	0	**0**	**0**	**0**	0	**0**	**0**	**0**	**0**	**0**