Bremen Energy Working Papers

Paperseries No. 48

Franziska Flachsbarth, Anna Pechan, Martin Palovic,
Matthias Koch, Dierk Bauknecht & Gert Brunekreeft

TSO Coordination and Strategic Behaviour: A Game Theoretical and Simulation Model Study based on the German Electricity Grid

July 2024

Constructor University Bremen
Bremen Energy Research (BER)

Editors:

Prof. Dr. Gert Brunekreeft

Dr. Marius Buchmann

Constructor University Bremen

Bremen Energy Research (BER)

Campus Ring 1 / South Hall

28759 Bremen

www.constructor.university

www.bremen-energy-research.de

Contact:

Dr. Marius Buchmann

Tel. +49 (0) 421 - 200-4868

E-mail mbuchmann@constructor.university.de

Suggested citing:
Flachsbarth, F., Pechan, A., Palovic, M., Koch, M., Bauknecht, D. & Brunekreeft, G. (2024), " TSO Coordination and Strategic Behaviour: A Game Theoretical and Simulation Model Study based on the German Electricity Grid", Bremen Energy Working Papers No. 48, Constructor University Bremen.

TSO Coordination and Strategic Behaviour: A Game Theoretical and Simulation Model Study based on the German Electricity Grid

Franziska Flachsbarth[1], **Anna Pechan**[2], **Martin Palovic**[2], **Matthias Koch**[1], **Dierk Bauknecht**[1,3] **& Gert Brunekreeft**[2]

[1]Öko-Institut, [2]Constructor University Bremen, [3]Albert-Ludwigs-Universität Freiburg

28/07/2024

Abstract

The electricity grid includes multiple network areas managed by different operators, with transmission system operators (TSOs) handling high-voltage areas and distribution system operators managing mid-to low-voltage areas. These areas are interconnected and synchronized, creating classical external effects where one operator's actions impact others. Recently, high voltage direct current (HVDC) lines have been introduced, offering operators greater flexibility and control over power flows compared to conventional alternating current (AC) lines, thereby reducing congestion and losses. However, HVDC lines can significantly affect neighbouring grids, potentially leading to strategic behaviour by network operators.

This paper examines the strategic use of HVDC lines, using a model-based approach on projected 2030 market data in the German electricity system. It finds that without explicit coordination mechanisms most hours result in incentives for non-cooperative outcomes, with only three hours within one year showing incentives for a cooperative outcome. Despite lower overall system costs with cooperation, asymmetric distribution of cooperation benefits prevents long-term cooperation. Thus, cost-revenue-sharing schemes are needed to promote cooperation and balance benefits.

Keywords

TSO coordination, strategic behaviour, game theory, simulation

Acknowledgements

The authors gratefully acknowledge financial support for the research grant “Whole System Approach: Anpassung der Anreizregulierung zur Verbesserung der Gesamtsystemoptimierung”, funded by Stiftung Energieforschung Baden-Württemberg (346-22). Furthermore, the authors are grateful for useful information and insights provided in interview with parties from the energy industry in Germany, as well as for constructive discussion and feedback from the participants of the Workshop of the “Gesellschaft für Operations Research e.V.” in October 2023 in Zürich[1] and of the economics colloquium at the University of Oldenburg in June 2024.

[1] https://www.gor-ev.de/workshop-der-ag-or-im-umweltschutz

1. Introduction

The electricity grid consists of several network areas that are each operated by a different network operator. There is one to few transmission system operators (TSOs) operating high-voltage transmission network areas and few to many distribution system operators operating mid- to low-voltage distribution network areas per country. These electricity network areas are interconnected and simultaneously synchronized. Due to this technical interdependence, the actions of one network operator may affect the network area of another network operator and vice versa. In economics, these are classical external effects.

In recent years, there has been an increase in implemented or planned high voltage direct current (HVDC) lines between network areas of different network operators. HVDC lines represent an innovative network component that provides network operators with additional flexibility in power network operation. In contrast to conventional alternating current (AC) lines, power flow on a HVDC line can be controlled more precisely and flexibly. This makes readjusting power flows on the AC lines of the system possible, as to reduce power network congestion or power network losses. Nevertheless, given the significant dimensioning of HVDC lines, their operation has typically a significant influence on the grids across several neighbouring network areas, i.e. is associated with significant external effects.

The use of flexibility that causes external effects, like the one associated with the HVDC line, has been suggested in the literature to be susceptible to strategic considerations of network operators (cf. Bjørndal et al. 2003, Glachant and Pignon 2005, Oggoni & Smeers 2013, Palovic 2022). It has been also technically demonstrated for two neighboring grid areas connected by an HVDC lines that the operation points, which are individually optimal, can differ from each other and also from the globally optimal solution (cf. Marten & Westermann, 2014). While well-founded in game-theoretical analysis, demonstrations of such strategic considerations have been thus far been limited to highly simplified representations of real-world networks at best.

Therefore, this paper contributes to the existing body of knowledge by examining network operator incentives towards strategic operation of the HVDC lines in a real-world setup. More precisely, we use a German transmission network model and make it subject to projected energy market data for 2030 for Germany. To translate the results of the grid model into a game-theoretical analysis, the operation of HVDC lines and the associated cost of network losses is compared for two setups: a setup where the overall system cost of network losses is minimized and a setup where every network operator minimizes the cost of network losses within the own network area. Costs of network losses account for a relevant proportion of ancillary service and grid, resp. system, security costs (cf. BNetzA & BKartA, 2023). Network operators might only partly reimburse these costs due to regulatory constraints (cf. PwC Strategy&, 2022[2]). To simplify the application of the game theory, the four German TSOs are merged in the model into two hypothetical operators. We use the German network for practical reasons but consider the design with the two adjacent TSOs exemplary for cross-border network operator constellations.

For the modelled year, we find most hours to provide incentives towards non-cooperative outcome when played as a single-shot game. In the remaining hours, network operators are indifferent between cooperative and non-cooperative behaviour. There are only three hours in the simulated year that result in a cooperative outcome. While the outcome of a repeated game-theoretical problem for the modelled year cannot be predicted without making further assumptions, it is striking that only one

[2] Other network costs that fall into the same category are congestion management costs, reactive power procurement costs, overheads and black start costs.

operator benefits from the system cost reductions promoted by cooperation, i.e. cooperation benefits are asymmetrically allocated.

The paper is structured as follows. Section 2 outlines the background of and literature on the problem of network operator coordination. In section 3, we describe the methodology and give the results in section 4. Section 5 discusses the results and sketches potential remedies. Section 6 concludes.

2. Modelling strategic behaviour in interactions of power network operators

This section introduces the problem of strategic considerations in the interactions of power network operators.

As suggested already above, electricity grid consists of several network areas that are each operated by a different network operator. Within a given network area, competition among power lines is uncommon, i.e. operators of these networks are natural monopolies that are subject to a so-called incentive regulation. Put in a nutshell, this regulatory regime caps the price or revenue of a network operator at a certain level. Herewith, not only overpricing of a monopolistic network service is prevented but also a high-powered incentive towards cost-efficient network operation is provided. It is common that each of the network operators in the electricity system has a strong incentive to minimize the cost at the individual level.

It is important to keep this incentive for individual cost minimization in mind when one considers that electric power flows from generation to consumption simultaneously across all AC-lines in the power system, i.e. through the network areas operated by the different network operators. Furthermore, power cannot be stored in large quantities what requires power production and consumption to be balanced across the system as a whole instantaneously. Clearly, taking a viewpoint of an engineer, this technical interdependency between network areas of different network operators makes their cooperation necessary as the power system is likely to be operated inefficiently or even malfunction otherwise. However, taking a viewpoint of an economist, internalizing such external effects is likely to act against the individual cost-minimization incentive, what might make cooperative behaviour irrational.

An interesting property of technical interdependencies in the electricity network is their reciprocal character. External effects among network areas of different network operators resulting from these interdependencies make the payoff of a given power network operator, i.e. the economic performance of the studied network area, not only dependent on the actions undertaken by this network operator, but also on the actions taken by others in the system. At the same time, the payoff of other network operators in the system is defined not only by their own performance, but also by the actions of the given network operator.

This setup is conductive to strategic interactions that are studied by the non-cooperative game theory. Put differently, it is rational for a network operator to compare different behavioural strategies when minimizing the own cost, with cooperative behaviour representing only one possible strategy among many.

Let us demonstrate this point with a simple numerical example. Assume two network areas with each managed by a separate TSO. The two network areas are connected by a HVDC line that is used to minimize the cost of network losses. Power flow at the HVDC line can be regulated between $0 < x < 10$. Furthermore, assume each TSO to be a subject to incentive regulation, i.e. to have a corresponding high-powered incentive to minimize the individual cost of power network losses. For a given hour, TSO-

1 minimizes own network losses by $\min_{x} c_{TSO1} = 5x$, i.e. by minimizing the HVDC line utilization. At the same time, TSO-2 minimizes own network losses by $\min_{x} c_{TSO2} = \frac{180}{x}$, that is by maximizing the HVDC line utilization. Correspondingly, power line losses of the overall system are minimized, i.e. reach the social optimum, when the HVDC line operates at $x = 6$. In case of a disagreement, i.e. when the two TSOs demand different operation levels, the HVDC line is operated at the average of the TSOs demands. This assumption is supposed to represent an expected value on a neutral dispute settlement mechanism, where each TSO has a 50 % chance of getting right. Also, we assume public information about costs, meaning that the TSOs cannot instruct a "fake" preference of line usage. Table 1 summarizes the payoffs of the two TSOs within the different scenarios that might emerge.

Table 1: Operation of HVDC line resulting from the different TSO strategies

Numerical example on the utilization of a HVDCline		TSO-1	
		Cooperate (Demand $x = 6$)	Defeat (Demand $x = 0$)
TSO-2	Cooperate (Demand $x = 6$)	$c_{TSO1} = 30$ $x = 6$ $c_{TSO2} = 30$	$c_{TSO1} = 15$ $x = 3$ $c_{TSO2} = 60$
	Defeat (Demand $x = 10$)	$c_{TSO1} = 40$ $x = 8$ $c_{TSO2} = 22.5$	$c_{TSO1} = 25$ $x = 5$ $c_{TSO2} = 36$

Will any of the two TSOs decide to behave cooperatively? When TSO-2 is expected to cooperate, i.e. demands the HVDC line to operate at $x = 6$, it is beneficial for cost-minimizing TSO-1 to defeat and demand $x = 0$. Assuming TSO-2 now to follow a different strategy and to defeat ($x = 10$), it is still the best strategy for TSO-1 to defeat. This means that defeating is the dominant strategy for the TSO-1. For TSO-2, it is the best strategy to defeat when TSO-1 defeats. Defeat is actually the best strategy for the TSO-2 even if the TSO-1 would cooperate. Put differently, defeat is the dominant strategy for both TSOs. Therefore, TSOs in the given example should not be expected to cooperate on the operation of the HVDC line unless the final allocation of cost is altered by the institutional setting.

The idea of power network operators behaving strategically when interacting with each other is not new. This has been originally suggested by Bjørndal and colleagues (2003) as well as by Glachant and Pignon (2005) in the context of congestion management in the Nordic power market. Having an option to address congestion by two different congestion management mechanisms, TSOs are shown on the example of a stylized 5-, resp. 8-node, network model to be capable of and to have an incentive towards behaving strategically by shifting the congestion cost to the other network operators in the system. Vincente-Pastor and colleagues (2019) suggested Shapley value as a cost allocation mechanism capable of addressing perverse network operator incentives, and the corresponding strategic behaviour, between transmission and distribution level when utilizing flexibility of distributed energy resources for system, respectively network, purposes. Le Cadre and colleagues (2019) use general Nash equilibrium model from non-cooperative game theory and its adoption on a stylized 18-node network model to test different coordination schemes between transmission and distribution network operators. They find sequential optimization, i.e. giving one network operator a priority with respect to acquisition of network and system services, to be particularly prone to strategic behaviour, as the privileged network operator might use this advantage to promote own interests. Using a stylized 4-node network model and assuming ideal conditions for power network operator cooperation (cf. Oggioni & Smeers 2013), Palovic (2022) suggests common redispatch situations in already a simple network topology to result in network operator pay-offs like prisoner's dilemma and chicken games, which are both well-known non-cooperative game theoretical problems conductive to strategic behaviour.

Even though the argument on strategic behaviour in interactions of power network operators is well-founded in the academic literature, stylized network models demonstrating the problem are thus far strongly simplified representations of real-world electricity networks. It is not possible to say how the incentive towards strategic behaviour manifests itself in a real-world setting, respectively whether cooperation among network operators is in reality at the risk.

This paper seeks to fill this research gap by modelling network operator incentives when operating the HVDC lines in a real-world electricity system. More specifically, we validate the hypothesis that non-cooperative game-theoretical problems emerge among the network operators when operating HVDC lines in the German transmission network.

3. Methodology

In this chapter, we provide a comprehensive overview of our methodology. We begin by introducing our subject matter, detailing the data for our calculations and justifying its representativeness for the underlying issue. We then elucidate our focus on analysing the target variable: the costs of grid losses.

Following this, we describe our modelling approach, with a specific emphasis on the integration of strategic games within an energy system model. The models are described in detail in a separate section. Lastly, we outline our method for analysing the model results through the lens of game theory.

3.1. Subject of investigation

Our network model corresponds to scenario B 2030 of the German Network Development Plan (BNetzA, 2019). The underlying grid corresponds to the information in the cited grid development plan, which contains the existing grid and the expansion requirements determined for the scenario year 2030 (BNetzA, 2020). Seven HVDC lines are integrated into the network topology. The grid is shown in figure 1.

To simplify the game-theoretical analysis performed in this paper, we use in the model only two instead of the four existing German TSOs. More specifically, we introduced two hypothetical transmission system operators that are aggregations of two real TSOs each: TSO-1, shown in shades of brown, whose grid area covers the areas operated by 50Hertz and TenneT, while the grid areas of Amprion and TransnetBW form the grid area of TSO-2, highlighted in shades of violet. Note that due to this simplification we do not speak of the German TSOs as such, but use realistic data to evaluate the possibility of non-cooperative game theoretical problems emerging in the interactions of power network operators in practice.

In addition to the operation of an HVDC line that connects two grid regions within a country, as in this example, this type of setup can also occur between different countries and market areas in the ENTSO-

E region and beyond. For example, numerous submarine cables are already in operation in the ENTSO-E[3] region:

- 17 cross border cables in the North Sea (e.g. NordLink[4] between Norway and Germany or North Sea Link[5] between Norway and UK)
- 9 cross border cables in the Baltic Sea (e.g. NorthBalt[6] between Lithuania and Sweden)
- 2 cross border cables in the Mediterranean Sea (e.g. MONITA[7] between Montenegro and Italy).

In addition, further cross-border DC cables are under construction (e.g. Biscay Gulf[8] between Spain and France) or in planning (e.g. between Italy and Tunisia).[9] The setup of HVDC lines between two grid areas in Germany considered in this study can therefore be understood as representative for other HVDC lines between different grid regions in Europe. While the HVDC lines between asynchronized network areas (continental Europe with UK, e.g. BritNed, and continental Europe and Skandinavia, e.g. NorNed) are operated on market-based schedules only, the operation of HVDC lines that couple synchronized grids (e.g. between France and Spain, between Germany and Belgium) is more freely adjustable by the operating TSOs (ENTSO-E, 2019). Cross-border HVDC connections are generally operated by either one TSO, two TSOs jointly or by an independent operator (cf. de Boeck & van Hartem, 2013). Depending on ownership and operating regime, the set-points of the HVDC lines (connecting to the TSOs areas) are fully, partially or at a cost available to the connected TSO; yet TSOs have little influence on the set-points of HVDC lines that are located outside their grid area (cf. de Boeck & van Hartem, 2013).

In the model, we abstract from any kind of coordination mechanism for the operation of the HVDC lines, except for an averaging of diverging TSO instructions as indicated in the numerical example above, to analyse whether coordination problems arise in the first place.

In the studied model, four of the seven HVDC lines connect both grid areas with each other (cross-grid area lines), see Figure 1. The remaining three HVDC lines are located exclusively in one grid area but their operation affects the power flows in the neighbouring grid areas. The two modelled grid areas are rather different from each other. Consisting of about 160 nodes and 270 AC lines, grid area of TSO-1 is much bigger than the grid area of TSO-2, which consists of about 120 nodes and 190 AC lines.

Demand in the two grid areas is roughly the same. However, the grid area of TSO-1 has significantly more renewable generation: it accounts for almost 60 % of PV generation and over 75 % of onshore wind generation. All of offshore wind generation is located in the area of TSO-1. This means that there will be a demand of electricity transport mostly from grid area of TSO-1 to the one of TSO-2.

We focus on the costs of network losses for two reasons: first, they account for a relevant proportion of the costs of ancillary services and grid, resp. system, security. For example, in Germany there made up about 13 % of total cost in 2021 (BNetzA & BKartA, 2023). Second, it is assumed that network operators can influence these costs and hence are incentivized to reduce them. In Germany and in the

---

[3] https://eepublicdownloads.entsoe.eu/clean-documents/Publications/maps/2023/230922/Map_ENTSO-E-4.000.000.pdf
[4] https://www.statnett.no/en/our-projects/interconnectors/nordlink/
[5] https://www.northsealink.com/
[6] https://www.nkt.com/references/nordbalt-the-baltic-sea
[7] https://www.4coffshore.com/transmission/interconnector-montenegro-italy-(monita)-icid63.html
[8] https://www.inelfe.eu/en/projects/bay-biscay
[9] The European Commission regularly publishes a list of projects of common interest (European Commission, 2024). https://energy.ec.europa.eu/news/166-key-cross-border-energy-projects-published-2024-04-08_en

Netherlands, bonus-malus systems are adopted for these costs. Similar applies also to redispatch costs (PwC Strategy&, 2022).

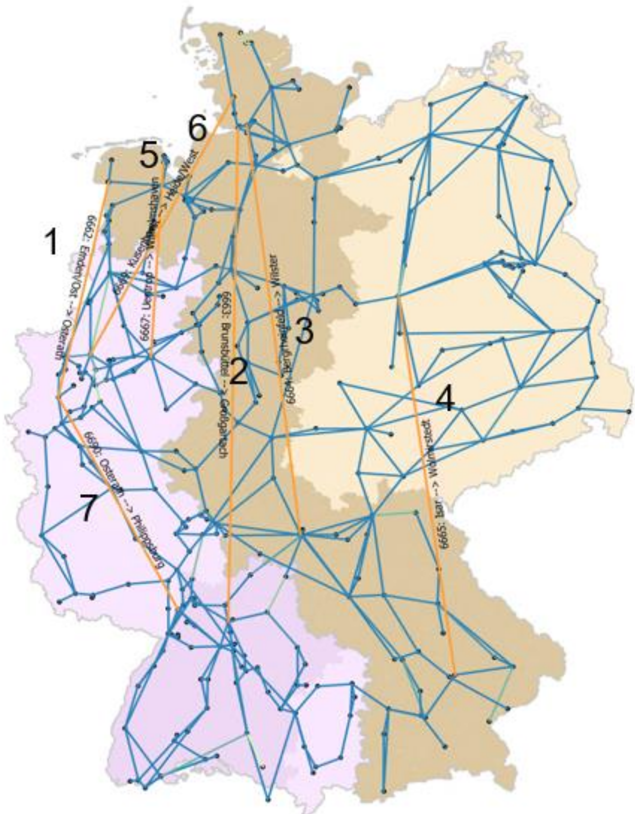

Figure 1: Underlying grid topology (AC-lines in blue, HVDC lines in orange, own numbering of HVDC lines) and aggregated grid areas (grid area 1 is coloured in brown and grid area 2 is coloured in violet)

3.2. Overall modelling approach

To examine the optimal dispatch of HVDC lines from different TSO strategies we use a three-stage modelling approach. The first step is to determine the market outcome as cost-minimal deployment of all available powerplants, storages and flexibility options in the European electricity market to meet demand in each hour of the scenario year 2030, using the single node dispatch model "PowerFlex", which is described in chapter 3.3.

Grid restrictions are not yet taken into account in the dispatch model. In order to calculate the resulting load flow in the high-voltage grid, the netted nodal loads at the transformer stations of the high-voltage grid are required. They result from the nodal feed-ins minus the nodal demand. To determine them, the market result must be regionalised accordingly. Then, the load flow optimization model "OptGrid" (Hobbie et al. 2022) is used in a second step to determine the resulting loadflow and to decide about the optimal operation of the HVDC lines to minimize the costs of line losses in the AC grid (chapter 3.3).

Costs can be minimized from two different perspectives: either the overall system costs (= line losses of the entire grid area) can be minimised, or an individual perspective can be adopted, for which only the line losses of the grid area of one network operator are relevant. In a well-designed economic system, social and individual optimizations are aligned. In order to test for such alignment in the studied model, three different optimizations must be solved:

- minimization of overall line losses (overall system perspective)
- minimization of only the line losses of the TSO-1 (individual optimization from the perspective of TSO-1)

- minimization of only the line losses of the TSO-2 (individual optimization from the perspective of TSO-2)

The resulting line losses of a time step are summed up for each TSO and can be written off in such payoff matrices as shown in table 2. There are four different possible combinations that can occur:

- Both TSOs act socially optimal and minimize line losses of the overall system (Cooperate-Cooperate = CC, 1).
- It is also possible that both TSOs act towards individual optimum (Defect-Defect = DD, 4).
- Finally, it is possible that one TSO minimizes the system losses, while the other TSO performs an individual optimization (Cooperate-Defect = CD, 2; Defect-Cooperate = DC, 3).

In all cases except in combination (CC, 1), it is possible that TSO-1 and TSO-2 have a different idea of how the HVDC line should be optimally operated in the respective hour: both give different and possibly contradicting instructions, which cannot be realized simultaneously. To resolve this problem, we assume a dispute settlement mechanism between the two instructions of the TSOs, which we call "clean up". In the model, we calculate the result of the clean up as the mean value between the two instructions. This corresponds to an expected value of each TSO on the dispute settlement when each TSO has a 50 % chance of winning the dispute. Further, we assume public information about costs, meaning that the TSOs cannot instruct a manipulated, strategic preference of line usage. These assumptions minimize the need to make assumptions on the design of the dispute settlement while keeping the results interpretable.

Once the operation of the HVDC lines has been determined, the third and final step in the optimisation chain, the clean-up, must be calculated. In the clean-up, the utilisation of the HVDC lines is fixed so that the final resulting load flow and the corresponding costs for line losses can be calculated.[10]

Table 2: Combination of different TSO strategies on HVDC line operation

Combination of different TSO strategies on HVDC line operation		TSO-1	
		Cooperate	Defeat
TSO-2	Cooperate	Overall societal minimum chosen by both TSO (CC, 1)	Costs of line losses resulting after the "clean-up" if TSO-2 has chosen its individual cost minimum while TSO-1 has acted according to the overall minimum (CD, 2)
	Defeat	Costs of line losses resulting after the "clean-up" if TSO-1 has chosen its individual cost minimum while TSO-2	Costs of line losses resulting after the "clean-up" if both, TSO-1 and TSO-2 have chosen to act according to their

[10] It should be noted that as a result the costs of line losses of the defecting TSO(s) are not necessarily less than or equal to the TSO's line loss costs after overall optimisation, as the averaging on the HVDC-lines leads to different load flows than assumed in the individual optimisation. Yet, this is only the case in less than 1.1% of hours, what we consider negligible.

		has acted according to the overall minimum (DC, 3)	individual cost minimum (DD, 4)

As it directly relates to this section, we first outline the game-theoretic interpretation of the results before we present the dispatch model "PowerFlex" as well as the load-flow and redispatch model "OptGrid" in Section 3.4.

3.3. The game theoretic interpretation of the results

This subsection outlines how the results of the simulation model are analysed from a game theoretic perspective.

In order to determine the game-theoretical problem faced by the network operators in the studied model, we begin the analysis by evaluating each hour of the studied year separately. For each hour and a TSO, we compare the payoffs (here costs) for four possible outcomes of network operator interactions:

- the studied TSO and the opponent cooperate (CC),
- the studied TSO cooperates and the opponent defeats (CD),
- the studied TSO defeats while the opponent cooperates (DC) and
- the studied TSO and the opponent defeat (DD).

This allows us to derive the strategies followed by the studied TSO in the given hour. Note that since we are considering costs, a lower outcome is preferred by the network operator. Given this information, strategies of the TSOs are combined to define the game-theoretical problem that characterizes the studied hour. Herewith, the expected outcome of the studied hour can be defined, i.e. it is possible to say whether cooperative or non-cooperative behaviour will occur.

In a second step, we consider the repetitive character of network operator interactions and focus on the long-term effect of cooperative behaviour on the TSO outcomes. We do so by evaluating the distribution of benefits from the mutual cooperation between the TSOs. When each TSO is found to prefer mutual cooperation against mutual defection in the majority of the studied hours, cooperation benefits are distributed rather equally between the two TSOs. This setup is conductive to cooperative behaviour, as long-term benefits of mutual cooperation incentivize network operators to forgo some short-term benefits of non-cooperative behaviour. The opposite indicates an unequal allocation of the cooperation benefits between the TSOs and makes cooperative behaviour less likely, as a long-term incentive towards cooperative behaviour is missing.

Before we move on to analysing the strategies, the dispatch model "PowerFlex" as well as the load-flow and redispatch model "OptGrid" are presented next.

3.4. The electricity system model "PowerFlex" and the load-flow and redispatch model "OptGrid"

"PowerFlex" is a fundamental electricity market model that determines the usage of thermal power plants, electricity feed-in from renewable energies, batteries and pumped storage power plants as well as flexible electricity consumers (demand side management) in a cost-minimising way to cover electricity and district heating demand. "PowerFlex" has complete foresight: all 8760 timesteps of a scenario year are optimized closed in one problem. The mathematical formulation of the model was first described in Koch et al. (2015). A detailed mathematical description of the used formulas and constraints can be found in Bauknecht et al. (2024).

The loadflow model “OptGrid” represents a DC loadflow calculation, which is to be understood as a linear approximation of the AC loadflow calculation, compare Van den Bergh et al. (2014). Each timestep of a scenario year is optimized separately, so that there are 8760 optimization problems to solve.

HVDC lines are taken into account by optimizing their operation in such a way that grid congestion is reduced. This option is usually supplemented by cost-optimal redispatch, which resolves all bottlenecks, as applied in Hobbie et al. (2022) for conventional redispatch and in Bauknecht et al. (2024) for flexibility options. But in this application, the operation of the HVDC lines is the only variable to reduce high line usages. In "OptGrid", line overloads are permitted but cause very high costs, so they are avoided wherever possible. This approach is known as the “soft constraints” approach, cf. “OptGrid” model description in Hobbie et al. (2022).

Classically, the approach is used to get rid of line overloads. However, the aim here is to minimise costs of line losses for AC-power lines v_{AC}, as expressed in eq. (1).

$$\min c = \sum_{t,v_{AC}} {f_{t,v_{AC}}}^2 * wf_{v_{AC}} * p^{el} \tag{1}$$

The squared line utilizations ${f_{t,v_{AC}}}^2$ are multiplied by a line-specific weighting factor $wf_{v_{AC}}$ representing the length and capacity of line $\boldsymbol{v_{AC}}$. The line losses must be offset by electricity purchased at the average electricity price p^{el} of the scenario year. It should be noted here that the target function still has an inherent incentive to avoid line overloads. This happens because the line losses increase quadratically with the transmission capacity.

In order to simplify to a linear optimisation problem, the squared line utilisation curve ${f_{t,v_{AC}}}^2$ at given parameters t and v_{AC} can be regarded as a function with f and approximated by a new, separate variable fs. For any given value of f this new variable is constrained downwards by the tangential line to the squared line utilisation curve at that value. By evaluating the variable fs at given base points b_p as values for f and minimising fs, the squared utilisation curve can be approximated (eq. 2).

$$\min c = \sum_{t,v_{AC}} fs_{t,v_{AC}} * wf_{v_{AC}} * p^{el} \tag{2}$$

For all base points b_p the following condition for the new variable $\boldsymbol{fs}$ must be given, in order to constrain it with the tangential lines of the squared line utilisation (eq. 3).

$$fs_{t,v_{AC}} > \left(2 * f_{t,v_{AC}} - b_p\right) * b_p \tag{3}$$

The restriction corresponds to the tangential lines of the squared function, and the “greater than” condition ensures that the value of the variable is kept high enough, while the target function tries to optimise it downwards. After we have adjusted the objective function in this way, we can apply it to the optimization problem for the different optimization perspectives and thus determine the instructions of the TSO for the HVDC lines. The more base points b_p are evaluated, the more accurate the approximation becomes.

4. Results

In the following, we first outline the utilization of the HVDC lines resulting from the different scenarios. We then show the results for the single hours (stage games) and subsequently derive the results for a repeated setting.

4.1. Utilization of HVDC lines

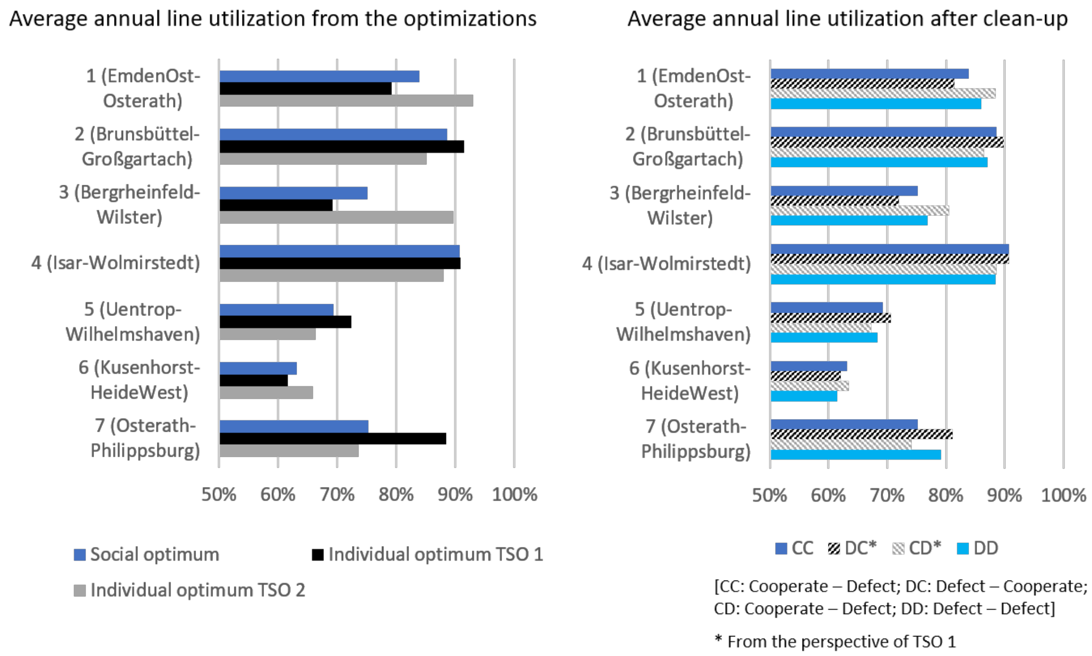

Figure 2: Average annual utilization of HVDC lines in different optimization perspectives before (left) and after clean-up (right)

The first relevant result of the modelling approach is the utilisation of the HVDC lines, which should depend on the optimisation perspective. Figure 2 shows the annual averaged optimal relative utilisation of the HVDC lines from the three optimisation perspectives on the left side of the figure. The resulting utilisation after the "clean-up" described above in the four different constellations is highlighted on the right side of the figure. The social optimum on the left side and the "CC" constellation are identical.

In general, the figure shows that the DC-corridors have a high average capacity utilisation, with an average utilisation of 80 % for all lines. Even the DC-corridor with the lowest average annual capacity utilisation (6: Krusenhorst-Heide/West) has an average capacity utilisation between 60 % and 70 % depending on the optimisation perspective.

The bars on the left-hand side of the figure, which illustrate the optimal utilisation of the lines from a societal or private perspective, show that the grid operators have different ideas about the optimal utilisation of the resource: On an annual average, the dispatching instructions of TSO-1 and TSO-2 can differ by at least 4 % (4: Isar-Wolmirstedt) and up to 20 % (3: Bergrheinfeld - Wilster). This indicates an existing coordination problem.

The coordination problem is more obvious in the case of an interzonal HVDC corridor, i.e. one that connects the two grid areas. However, because they severely impair the flow of electricity on the neighbouring lines, it also exists on intra-zonal HVDC lines, i.e. those that extend exclusively within a grid area: Two of the three HVDC power lines (HVDC 3 and 7), which differ greatly in their optimal utilisation, are intra-zonal resources.

Apart from the "CC" constellation, which coincides with the action instruction according to the social optimum (dark blue bars on the left and right), the resulting corridor utilisation must first be derived in a subsequent step for every other constellation. This is because the bars on the left only reflect the perspective of one TSO in these cases, i.e. this line utilisation would only result if the TSO could dictate the utilisation. Since both TSOs have a say in the utilisation of the resources, we apply the clean-up described above. The resulting utilisation, if at least one player deviates from the cooperative result (shown on the right), therefore lies between the two contradictory instructions of the grid operators, e.g. in the case that both defect ("DD") in the middle of the black and grey bars on the left. The socially optimal line utilization always represents a more moderate result between the individual instructions by the TSOs: it is always between the two conflicting individual optima. The averaging of the instructions therefore leads to more moderate results than the extremes after individual optimisation. That's why the effects on the resulting costs of grid losses decrease compared to the results after individual optimisation.

Now that we have shown that the optimal utilisation of DC-corridors varies from TSO to TSO, we analyse the incentives to deviate from the overall social optimum.

4.2. Network operator strategies and resulting games in single stages

In the following, we first outline the strategies of each TSO separately, taking each hour as a separate stage game (n=8,760). The resulting games of the TSOs are analysed subsequently.

Network operator strategies

In order to get an insight into how network operators can be expected to behave, resp. what strategies these will follow, we analyse their payoffs in each hour. A dominant strategy exists when one TSO would always defect – DD (or always cooperate - CC) independent of whether the counterpart is expected to defect or to cooperate. If defecting is the dominant strategy this will result in lower or equal costs than cooperating (DC≤CC and DD≤CD)[11]. The opposite is true in the case of cooperation as a dominant strategy (CC≤DC and CD≤DD). In addition to the dominant strategies, the TSOs may be indifferent between defecting and cooperating (DC=CC and DD=CD), may want to do the opposite of the expected behaviour of the opponent (DC<CC and CD<DD) or may want to do the same of the expected behaviour of the opponent (CC<DC and DD<CD).

As illustrated in Figure 3, for both TSOs the dominant strategy in the majority of hours (72 and 80 % respectively) is to defect. In contrast, cooperation is a dominant strategy in less than 1 % of the hours for each TSO. In the remaining hours, the TSOs are mostly indifferent between cooperating and defecting.

[11] Note that this excludes being indifferent, i.e. DC=CC and DD=CD. Furthermore, one may differentiate weakly dominant from strictly dominant strategies. In the latter case, defecting would result in strictly lower costs than cooperating, i.e. DC<CC and DD<CD. Yet, this differentiation does not add to our analysis.

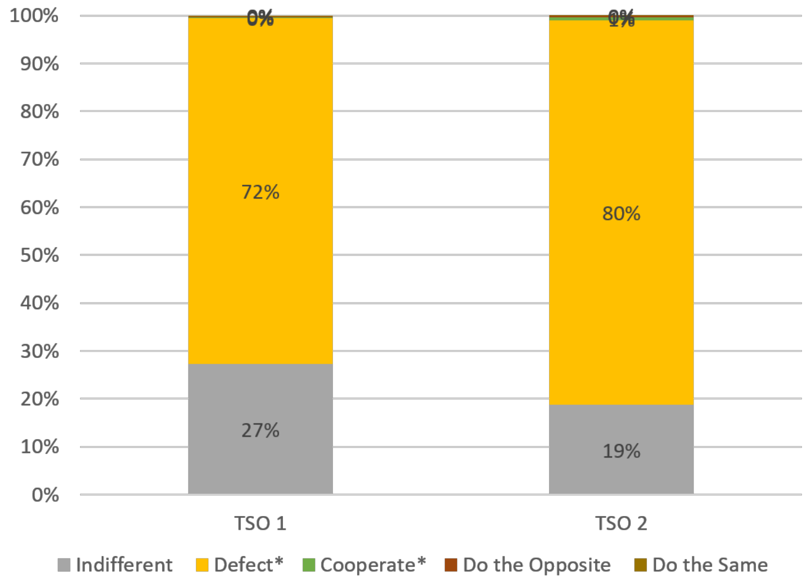

*Figure 3: Overview in network operator strategies (in share of hours, n=8,760, *excluding indifferent)*

Second, we analyse the strategies in more detail by additionally analysing the costs of mutual cooperation and mutual defection (CC and DD). Except for 1 % of the hours, the TSOs always follow one of the following four strategies. Note that strategy names used are our own creation.

a) "Hoping for Mutual Cooperation": the TSO is indifferent between cooperating and defecting (DC=CC and DD=CD) but prefers mutual cooperation against mutual defection (CC<DD).
b) "Completely Indifferent": the TSO is completely indifferent (DC=CC and DD=CD) and in contrast to "Hoping for Cooperation" has no preference for mutual cooperation or defection (CC=DD).
c) "Defect with Regret": defection is the dominant strategy (DC≤CC and DD≤CD), but the TSO prefers mutual cooperation over mutual defection (CC<DD). If this strategy applies for both TSOs simultaneously it results in a classical prisoners' dilemma.
d) "Defect without Regret": defection is the dominant strategy (DC≤CC and DD≤CD) and mutual defection is also preferred over mutual cooperation (DD<CC). Note that due to the selection criterium of the hours this strategy cannot apply for both TSOs simultaneously.

In more than half of the hours (61 %), the TSO of zone 1 can be expected to follow the strategy "Defect with Regret" and in 10 % "Defect without Regret". In approximately one fifth of the hours the TSO's strategy is "Completely Indifferent" and in 10 % it is "hoping for mutual cooperation" (see Figure 4).

The picture is again different for the TSO of zone 2. In almost half of the hours (47 %) the TSO follows the strategy "Defect without Regret" and in one third of the hours it is "Defect with Regret". In approximately one fifth of the hours the TSO's strategy is "Completely Indifferent" and in 1 % of the hours it is "Hoping for Mutual Cooperation" (see Figure 4).

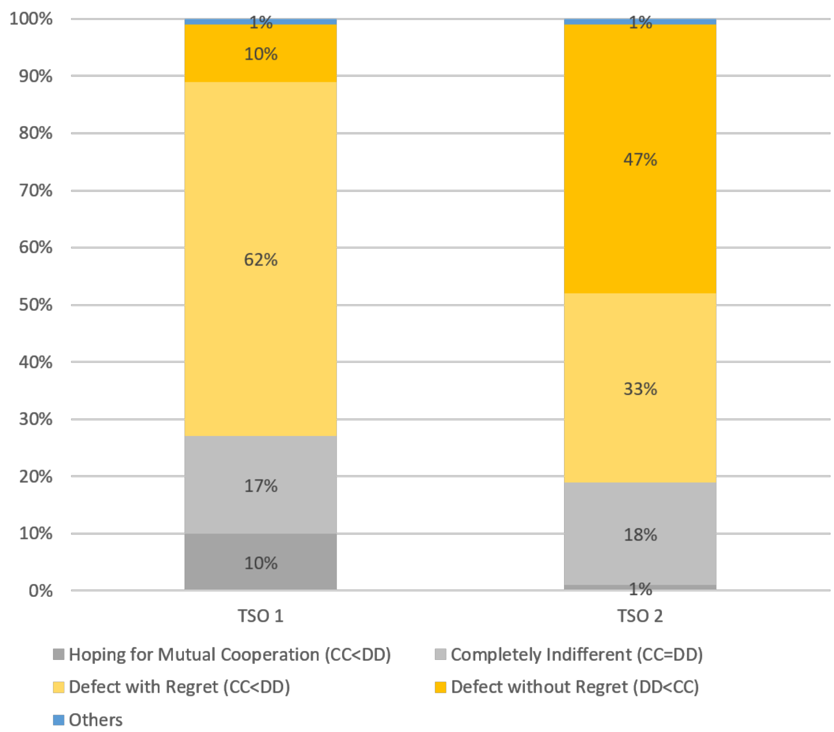

Figure 4: Detailed strategies of the two TSOs (in share of hours, n=8,760)

Network operator stage games

The four outlined strategies can be theoretically combined to 10 different stage games. In 98% of the hours of the studied year, we find only the following four stage games (see also Figure 5):

(1) “Defect without Regret” and “Defect with Regret” (46 %), which we term briefly “Defect with/out Regret"
(2) “Defect with Regret” by both (24 %), i.e. a classical prisoners’ dilemma
(3) “Completely Indifferent” by both (17 %) which we term “Game of Indifference”
(4) “Defect without Regret” and “Hoping for Cooperation” (10 %)

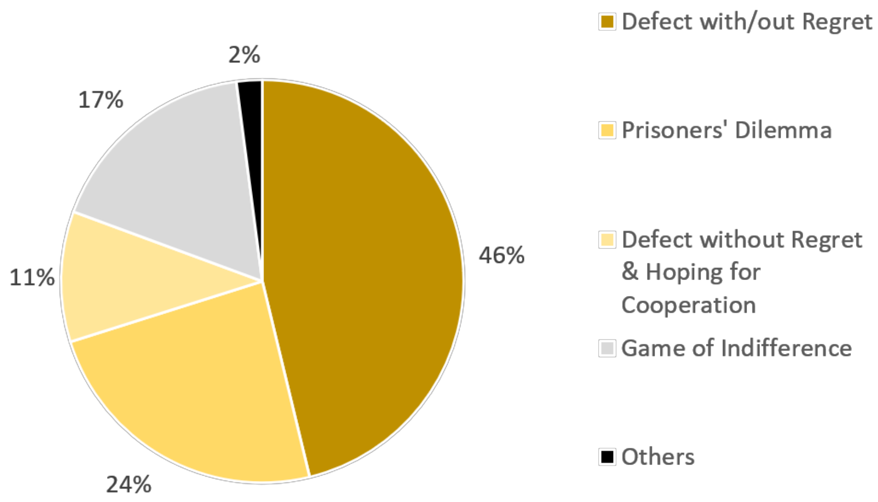

Figure 5: Games of the TSOs (in share of hours, n= 8,760))

“Defect with/out Regret” is the most frequent game, occurring in almost every second hour of the analysed year. Therefore, we illustrate it by the simulation results of hour 3 in Table 3. Defecting is the dominant strategy of both TSOs, although for TSO-1 mutual cooperation would result in the lowest cost. Consequently, the outcome of this single-shot stage game is mutual defection.

Table 3: Example of costs of energy losses of each TSO (in red and blue) and in sum (in black) for each combination of decisions (t=3) of the game of “defect without regret” and “defect with regret”. The dominant strategies and outcome are marked in bold.

		TSO-2 (defect without regret)	
		Cooperate	**Defect**
TSO-1 (defect with regret)	Cooperate	18,796 9,425 ∑=28,221	19,327 9,256
	Defect	18,756 9,482	**19,123** 9,298 **∑=28,421**

It is worth noting that the other prominent games do not result in mutual cooperation neither. Actually, only in three hours of the studied year both TSOs would chose to cooperate simultaneously, i.e. only in 0.03 % of hours mutual cooperation would result. In the other games, at least one TSO can minimize the cost of network losses by opting for a non-cooperative behaviour or the outcome cannot be predicted as both TSOs are indifferent.

4.3. Grid operation as a repeated game

Network operators interact with each other repeatedly and with no predetermined endpoint when it comes to the operation of the HVDC lines, as shown in the model. This means that the total cost of a network operator is defined by the sum of costs collected over many games. Being aware that the game played in the given hour has an extremely low probability of becoming the last one, network operators might opt for a different strategy than they would otherwise. The prisoner’s dilemma game observed in the model is a common example for this. While a prisoner’s dilemma in a single shot setting leads to mutual defection, it is likely to result in mutual cooperation when the probability of repeating the game in the next round is high. For this, the players, i.e. network operators, who are in a repeated setting are assumed to recognize the long-term benefits of cooperation and optimize these against the short-term losses of cooperation. However, a repeated setting does only imply a strategy change compared to a single-shot game when it pays off. Consider for example the most frequent game occurring in our model, i.e. defect with/out regret, as portrayed in table 1. In this game, if TSO-2’s dominant strategy is throughout "defect without regret" the benefits from mutual defection exceed those from mutual cooperation. Therefore, we next analyse the overall incentives over the total sum of the studied hours.

The TSO of zone 1 is found to prefer mutual cooperation (CC) over mutual defection (DD) in most of the selected hours (72 %), see Figure 6. The contrary is the case in 11 % of the hours and in another 17 % of the hours the TSO can be expected to be indifferent, as both result in the same costs.

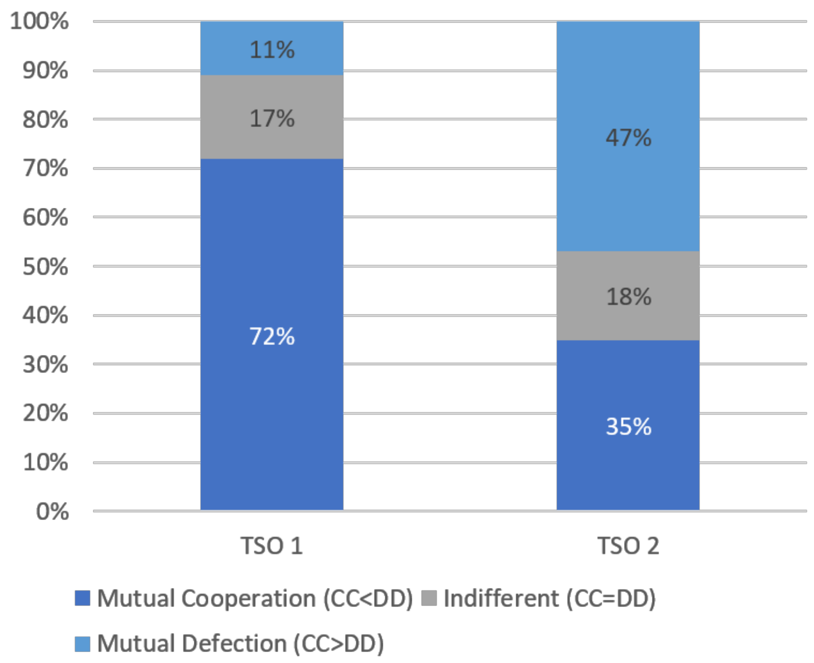

Figure 6: Incentives of the two TSOs for cooperation or defection (in share of hours, n=8,760)

The picture is different for the TSO of zone 2, who can be expected to prefer mutual defection over mutual cooperation in almost half of the selected hours (47 %). Mutual cooperation is preferred in 35 % of the cases (see Figure 6). Both CC and DD result in the same level of costs in 18 % of hours.

In absolute figures, mutual cooperation leads to lower costs for TSO-1 in the studied year than mutual defection (178.8 Mio. € compared to 180.6 Mio. €). This means that mutual cooperation would in the long term pay off for TSO-1. In contrast to TSO-1, mutual defection leads to (slightly) lower costs for TSO-2 in the studied year compared to mutual cooperation (97.1 Mio €. compared to 97.2 Mio €). In other words, there is no long-term benefit in a repeated setting that would motivate TSO-2 to change its strategy. In sum, however, the two TSOs together would be better off when cooperating in all hours, resulting in costs of 276.1 Mio. € compared to 277.7 Mio. € in the case of both permanently defecting. Hence, although overall system costs are the lowest with cooperation, one operator does not incur a long-term benefit from cooperating due to asymmetrical distribution of cooperation benefits between the TSOs.

5. Discussion and remedies

In this section we discuss the results and potential limitations of our findings as well as remedies addressing the risk of non-cooperative outcome.

The results of the model presented in section 4 indicate an incentive towards non-cooperative behaviour for one of the modelled TSOs. The difference in total costs of network losses between mutual cooperation and mutual defection are, however, relatively small. One reason for this is the averaging (i.e. clean-up) conducted to handle deviating instructions on the HVDC operations, which was also applied all HVDC lines. The cost differences are likely to be larger (as indicated by the differences of individual optima in Figure 2), if one assumes that one TSO can determine the operation point of a line alone, which is particularly realistic for the intrazonal lines. Another reason may be that the two TSOs in the model are within the same bidding zone and thus have similar procurement costs for network losses per MWh. This is likely to differ for TSOs that are in different bidding zones, which is the standard case in the European context.

From a game-theoretical point of view, one might argue that the results presented in section 4 are only indices for non-cooperative outcome but that the final strategy adopted by the TSOs is undefined. The problem of defining the strategy 'played' by the TSOs in the modelled year requires finding an optimal strategy for a game-theoretical problem where the played game is assumed to have a low probability to be the last one, with the next game(s) being chosen at random from a finite set of different stage games[12]. To our knowledge, it is not possible to solve the problem without making further assumptions on the TSO behaviour and capabilities (cf. Carroll 2020). Therefore, the presented results should not be understood to exclude the possibility of mutually cooperative outcomes from emerging. These rather demonstrate that network operator cooperation, when observed, is likely to be fragile without a supporting regulatory framework.

The results may further differ if one assumes line losses and related costs to be private information of the TSOs, as was done when analysing strategic network behaviour in redispatch by, e.g., Oggoni & Smeers (2013) and Glachant & Pignon (2005). This would change the nature of the game substantially because the TSOs would, for example, follow more complex and cautious strategies such as "faking" preferences of line utilization. It could also increase the difference in costs between individually and socially optimal line utilization.

A further limitation of our approach is that we restrict our considerations to the optimized operation of HVDC lines to reduce grid congestion and do not yet include redispatch in our considerations. The resulting grid utilization and line loss costs will not occur in this way in reality, as a grid that remains congested in this way is not an acceptable solution for grid operation. The inclusion of redispatch therefore represents the next logical step, which should follow from this investigation and would provide us with a more complete estimate of future grid costs that are estimated to be controllable by the TSOs. Including redispatch costs is likely to increase the cost differences between individually and socially optimal operation of the HVDC lines.

To ensure mutual cooperation among modelled network operators, additional measures are likely to be needed. In Brunekreeft et al. (2024) we give an overview and analyse policy measures that apply a whole system approach, i.e. address coordination and cooperation problems between the energy sectors and use this case study as one example. Here we give the essence of our recommendation for this case.[13] Given the unequal distribution of the cooperation benefits observed in the model, we suggest introducing a cost-revenue sharing between the TSOs to align incentives. Cost-revenue-sharing aims to internalize external (spill-over) effects of one network on other networks or sectors. This is well known and often used in the economy and society at large, sometimes also called cost-benefit-sharing. The key idea is to re-align misaligned incentives of independent actors by using side-payments for cost or revenues allocation.

In this case, we would propose an ex-post financial compensation mechanism (e.g. at the end of a month or year) because, first, we would expect many frequent and repeating coordination problems, which will be better addressed in a one-off all-inclusive negotiation round after the events. Second, we expect that many potential conflicts are not known ex ante. These events are important for the pay-offs, and therefore decisive for compensation payments. Under uncertainty, these can best be addressed ex post.

[12] This argument is elaborated in Palovic (2022).

[13] The interested reader is referred to the policy report, in which we discuss the suggested measures in more detail.

Cost-revenue sharing can largely internalize incentive problems, but it is unlikely to resolve all of them. More importantly, it may not address urgent issues requiring immediate and clear decisions. Therefore, an effective approach to this case involves establishing a competence hierarchy. For example, a TSO could be given the authority to decide in cases of doubt or conflict. This authority could be granted either by law or through mutual agreement among the relevant stakeholders, such as the TSOs. However, we believe that competence hierarchy alone may not fully address the issue. While it can lead to effective decisions, these decisions may not always reflect the financial interests of all parties involved. As a result, the decisions made by a competence hierarchy might be suboptimal overall. Consequently, we recommend limiting the use of competence hierarchy to urgent, high-impact cases only.

Within Germany, in fact, for redispatch a competence hierarchy exists among the four TSOs, which is done for Germany as a whole, and may include the utilization of HVDC lines in the future.[14] On the European level this is not the case so far; yet, a European redispatch for the CORE area is to be introduced from 2025 to strengthen coordination between the grid operators.[15] Regarding the coordination of HVDC line operation specifically, ENTSO-E (2019) states that it is an established method of cooperation between TSOs, which is required when two or more TSOs are affected by a HVDC line. However, the details remain unclear and despite existing cooperation mechanisms such as improved information exchange, incentive problems may still remain, as e.g. Palovic (2022) analysed for the case of redispatch.

Again for the German TSOs and for redispatch costs a common incentive mechanism exists, i.e. all receive a capped bonus (malus) if the sum of redispatch costs are below (above) a defined reference value (§ 17 ARegV). This should set similar incentives as the proposed cost-revenue sharing approach. However, it is not readily applicable to TSOs from different countries that underlie different regulatory schemes. Furthermore, to our knowledge, there is no similar common incentive mechanism for costs of line losses on a national or international level. Therefore, we see a need for the above suggested policy action.

6. Conclusion

The electricity grid comprises several interconnected areas managed by different network operators, including high-voltage transmission system operators (TSOs) and distribution system operators handling mid- to low voltage areas. These operators, considered natural monopolies, are regulated to keep prices or revenues at a certain level, incentivizing individual cost minimization. At the same time, the technical interdependence of the network areas means that actions by one operator can affect another's costs, creating external effects. For example, the actions taken by one network operator to reduce own costs of grid losses might affect the grid losses in another grid area.

This setup is susceptible to strategic interactions between the network operators. This paper explores potential incentives for non-cooperation using the example of operating HVDC lines when minimizing own costs of network losses. Applying a game theoretical perspective, we do so by simulating the future electricity grid of Germany with realistic market and grid data of the scenario year 2030, focusing on two hypothetical grid operators. This setup should be representative for two TSOs within one country, e.g. Germany, but also for two TSOs from different countries that are connected via an HVDC line.

[14] This information was provided in interviews we held with TSOs in the course of this study. The TSOs Amprion and 50Hertz were stated to host the central coordination of redispatch for all TSOs.
[15] This information was provided in interviews we held with TSOs in the course of this study.

We have noted that in most hours (83 %) of the scenario year, the two TSOs have different needs in terms of how the HVDC line should be operated to minimise line losses in their own grid area. This shows that there is a coordination problem.

We have also found that, when viewed as a single-shot game, non-cooperative behaviour occurs in most hours: there are only three hours in the modelled year (0.03 %) that results in a cooperative outcome. In contrast, in 81 % of the hours the setup results in non-cooperative game-theoretical problems, with outcomes reflecting non-cooperative behaviour. In the remaining hours, network operators are indifferent between cooperative and non-cooperative behaviour. The outcome of a repeated game-theoretical problem for the modelled year cannot be predicted without making further assumptions due to the uncertainty about the next game. However, it is striking that one network operator incurs lower costs over the entire year in a non-cooperative scenario than in a cooperative one. This indicates that although overall system costs are lowest with cooperation, one operator does not benefit in the long-term from cooperating due to asymmetrical distribution of benefits. Therefore, remedies are recommended to address this imbalance and promote cooperation. Because the difference between cooperation and non-cooperation are relatively small, such measures need not be drastic. We suggest to introduce ex post cost-revenue sharing to re-align misaligned incentives and competence hierarchy to resolve urgent conflicts with a high impact (cf. Brunekreeft et al. 2024 for a more detailed discussion of the suggested measures). Existing cooperation agreements between TSOs should be reviewed accordingly to be able to exclude misaligned incentives.

In this paper we have focused on the costs of line losses in determining the individually or socially optimal operation of the HVDC lines. The next step is to also include redispatch costs in the optimizations.

References

Bauknecht, D., Flachsbarth, F., Koch, M., & Vogel, M. (2024). The role of decentralised flexibility options for managing transmission grid congestions in Germany. *The Electricity Journal, 37*(1), 107363. https://doi.org/10.1016/j.tej.2023.107363

Bjørndal, M., Jørnsten, K., & Pignon, V. (2003). Congestion management in the Nordic power market – counter-purchases and zonal pricing. *Journal of Network Industries, 4*(3), 271-292.

de Boeck, S., & van Hertem, D. (2013). Coordination of multiple HVDC links in power systems during alert and emergency situations. *Powertech, IEEE, IEEE Grenoble Conference*. https://doi.org/10.1109/ptc.2013.6652278

Brunekreeft, G., Bauknecht, D., Palovic, M., Pechan, A., Flachsbarth, F., & Koch, M. (2024). Policy measures to apply the Whole System Approach (WSA) in energy infrastructures. *Bremen Energy Working Papers, (47)*, June 2024.

Bundesnetzagentur (BNetzA) & Bundeskartellamt (BKartA). (2023). *Monitoringbericht 2023*. Bonn. https://data.bundesnetzagentur.de/Bundesnetzagentur/SharedDocs/Mediathek/Monitoringberichte/MonitoringberichtEnergie2023.pdf

Bundesnetzagentur (BNetzA). (2019). *Bedarfsermittlung 2019-2030, Bestätigung Netzentwicklungsplan Strom*, Bonn, Dezember 2019. https://www.netzentwicklungsplan.de/sites/default/files/2022-11/NEP2019-2030_Bestaetigung.pdf

Bundesnetzagentur (BNetzA). (2020). *Anhang zum Netzentwicklungsplan Strom 2030, Version 2019, zweiter Entwurf, Aktualisierung Januar 2020*. https://www.netzentwicklungsplan.de/sites/default/files/2022-11/NEP_Anhang_Aktualisierung_Januar_2020.pdf

Carroll, G. (2020). Dynamic incentives in incompletely specified environments. *SET: Seminars in Economic Theory*. Retrieved December 30, 2021, from http://individual.utoronto.ca/carroll/onelongrun.pdf

ENTSOG & ENTSO-E. (2018). *Ten Year Network Development Plan 2018, Scenario Report, Main Report*. https://eepublicdownloads.entsoe.eu/clean-documents/tyndp-documents/TYNDP2018/Scenario_Report_2018_Final.pdf

ENTSO-E. (2019). *HVDC Links in System Operations, Technical Paper.* https://eepublicdownloads.entsoe.eu/clean-documents/SOC%20documents/20191203_HVDC%20links%20in%20system%20operations.pdf

European Commission. (2024). *COMMISSION DELEGATED REGULATION (EU) 2024/1041 of 28 November 2023 amending Regulation (EU) 2022/869 of the European Parliament and of the Council as regards the Union list of projects of common interest and projects of mutual interest*. https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=OJ:L_202401041

Glachant, J.-M., & Pignon, V. (2005). Nordic congestion's arrangement as a model for Europe? Physical constraints vs. economic incentives. *Utilities Policy, 13*, 153-162.

Hobbie, H., Mehlem, J., Wolff, C., Weber, L., Flachsbarth, F., Möst, D., & Moser, A. (2022). Impact of model parametrization and formulation on the explorative power of electricity network congestion management models - Insights from a grid model comparison experiment. *Renewable and Sustainable Energy Reviews, 159*, 112163. https://doi.org/10.1016/j.rser.2022.112163

Koch, M., Bauknecht, D., Heinemann, C., Ritter, D., Vogel, M., & Tröster, E. (2015). Modellgestützte Bewertung von Netzausbau im europäischen Netzverbund und Flexibilitätsoptionen im deutschen Stromsystem im Zeitraum 2020–2050. *Zeitschrift für Energiewirtschaft, 39*(1), 1-17. https://doi.org/10.1007/s12398-015-0147-2

Le Cadre, H., Mezghani, I., & Papavasiliou, A. (2019). A game-theoretic analysis of transmission-distribution system operator coordination. *European Journal of Operational Research, 274*, 317-339.

Marten, A.-K., & Westermann, D. (2014). Local HVDC grid operation with multiple TSO coordination at a global optimum. *ENERGYCON*. https://doi.org/10.1109/energycon.2014.6850629

Oggioni, G., & Smeers, Y. (2013). Market failures of market coupling and counter-trading in Europe: An illustrative model based discussion. *Energy Economics, 35*, 74-87.

Palovic, M. (2022). Coordination of power network operators as a game-theoretical problem. *Bremen Energy Working Papers, (40)*.

PwC Strategy&. (2022). Improving TSO regulation in the context of the European Green Deal. Prepared for TenneT. https://tennet-drupal.s3.eu-central-1.amazonaws.com/default/2023-01/220801%20TSO%20regulation%20improvements_TenneT%20paper_vSTC1_signed.pdf

Van den Bergh, K., Delarue, E., & D'haeseleer, W. (2014). DC power flow in unit commitment models. *TME Working Paper, (WP EN2014-12)*.

Vincente-Pastor, A., Nieto-Martin, J., Bunn, D. W., & Laur, A. (2019). Evaluation of flexibility markets for retailer-DSO-TSO coordination. *IEEE Transactions on Power Systems, 34*(3), 2003-2012.