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Author for correspondence:
E. Karangelos
e-mail: e.karangelos@uliege.be

"Cooperative game" inspired approach for multi-area power system: day ahead – intraday markets & security management taking advantage of grid flexibilities

Efthymios Karangelos[1] and Patrick Panciatici[2]

[1] Montefiore Institute - Department of EE & CS, Université de Liège, Liège, Belgium.
[2]Reseau de Transport d' Electricité (RTE), Paris La Défense, France.

This paper advocates for a progressive rethinking of the day-ahead/intra-day power system security management practice in the low-carbon energy transition era. As a starting point, the need for multi-TSO coordination in order to efficiently exploit the value of grid flexibility towards operating the low-carbon, multi-area power system securely and economically is established. On this basis, the core proposal of this paper is the adoption of a new approach to day-ahead/intra-day multi-area power system security management, inspired from the principles of cooperative game theory. The proposed approach relies on counterfactual analysis to evaluate the (positive and/or negative) impact of each distinctive control-area to the common security of the multi-area system, thus providing clear economic incentives to achieve the required coordination. This proposal is not a marginal approach and notably facilitates the integration of more detailed physical modeling (including the non-convexities of the power system) in the inter-TSO settlement of the multi-area interconnected system security management cost. The proposed framework allows some level of subsidiarity and the definition of hedging products to cover ex-post costs. Further from the blueprint of the proposed approach, the paper discusses prominent research and development pathways in order to progressively put such vision into practice.

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1. Introduction

As the clean energy transition advances, the wider integration of national and regional electricity markets along with the growth of renewable and distributed generation resources are jointly challenging multi-area power systems operation. Larger and larger energy volumes are financially exchanged across the "electrical borders" of multi-area interconnected systems whilst physical power flow patterns are becoming more and more random. Both these effects increase generation redispatch costs and lead to operating the system closer to its security limits [1].

Widening the integration of security management practices by the enhanced coordination of regional *Transmission System Operators* (TSOs) is an obvious countermeasure to the modern multi-area power system challenges. The technical and economic benefits of such enhanced TSO coordination are by now well documented [2,3]. Rather than beneficial, enhanced coordination becomes necessary for the operation and further development of a multi-area power system with *grid flexibility* resources (*i.e.*, topological reconfiguration, dynamic transmission ratings, phase-shifting transformers, *etc.*). From an operational standpoint, the activation of "local" grid flexibility actions by the respective TSO within its control area may "globally" re-route power flows and transfer congestion to a different control area [4]. Therefore, operational efficiency can only be maximized when grid flexibility resources are employed in a mutually acceptable manner. Similarly, from a long-term standpoint, relying only on the "local" impact of grid flexibility to stimulate further development would naturally result in developing grid flexibility resources at sub-optimal grid locations.

To date, the incentive structure for achieving the required level of coordination in a multi-area system with grid flexibility is unclear. On the one hand, the physical properties of grid flexibility are beyond the simplified (convex) nodal grid representation adopted in the electricity market. Integrating such resource in forward (*i.e.*, long-term, day-ahead and intra-day) markets may only happen after an excessive rethinking of the market clearing assumptions and algorithms, as well as of the respective settlement schemes. Therefore, there is presently no market-based valuation for grid flexibility. On the other hand, present inter-TSO compensation schemes used to share cross-border congestion management costs (see, for instance [5–10]) are also unsuitable. First, these methods have been proven highly sensitive to power-flow controlling measures [11]. Further, they only account for (negative) costs, associated to the transit power flows through one's part of the multi-area system. Doing so, the methods fail to account for the (non-negative) value of TSO grid flexibility, which is an intra-area resource that can be used to securely accommodate power flows throughout the interconnected network [12].

In the present paper we revisit the framework for multi-area power system operation with grid flexibility. We focus on the point after the execution of forward cross-border markets for energy and argue for the coordinated mobilization of all redispatch and grid flexibility resources by the multi-area system TSOs. To provide the necessary incentives for cooperation, the core proposal of this paper is a methodology to share the costs and benefits of coordinated security management between cooperating TSOs of a multi-area system. The methodology relies on counterfactual analysis to quantify the contribution brought in by any single TSO to securing the interconnected system. More specifically, we propose a set of *what-if* analyses to compute the change in the system security management cost (i) without the fixed physical limitations (*i.e.*, transmission capacities, reactances, security criteria, *etc.*) of each distinctive control area, and, (ii) without the grid flexibility of each distinctive control area. Using the former as an indicator of economic loss and the latter as an indicator of economic benefit, we introduce a settlement scheme to share the total cost of security management while rewarding control areas with grid flexibility of value to the system. Notice that the approach relying on *what-if* analysis is not a marginal approach and therefore facilitates the integration of more detailed physical modeling in the settlement scheme. Indeed the non-convexities of the power system pose no conceptual challenge here (albeit, these remain of course a technical challenge for optimal decision making). Finally, the proposed settlement scheme focuses on sharing the security management costs at the inter-TSO level and is compatible with any mechanism for the further allocation of such costs to the system users at the intra-TSO (regional) area level.

2. Coordination framework for multi-area power system operation

This section provides a high-level description of the proposed approach for exploiting grid flexibility in a multi-area power system. We focus on the operational timeframes and discuss the three typical phases of deregulated power system operation, namely: (a) *ex-ante* market execution, (b) secure physical delivery and (c) *ex-post* financial settlement.

(a) *Ex-ante* market execution

Ever since deregulation, the execution of forward markets for electrical energy has been based on the stylized “bus-branch” modeling of the high-voltage transmission grid and the linear “DC power flow” approximation of the respective physics. At the expense of (tolerable) inaccuracies, these features combined produce market-clearing optimization problems with desirable mathematical properties, ensuring the availability of robust solution algorithms and of unique (or at least, indisputable) optimal solutions. Unfortunately, such simplifying assumptions restrict the potential to explicitly represent grid flexibility during the *ex-ante* electricity market execution phase. Indicatively, explicit modeling of topological reconfiguration would require replacing the “bus-branch” model by the more detailed and more complex “node-breaker” model, featuring a set of binary decision variables per bus of the original “bus-branch” grid. Such a transition would obviously have numerous implications on the market actors’ exposure to risk, the definition of essential concepts such as the short-term locational marginal prices, the long-term financial transmission rights *etc.*, not to mention the implied explosion of computational complexity.

Rather than supporting such a radical (perhaps, even unattainable) reorganization for electricity trading, our viewpoint is that grid flexibility can and should be exploited by TSOs to ensure that the market execution outcome is implemented as closely as possible through the physical transmission system. To allow for this, it suffices that forward markets are organized at a granularity of several locational hubs (analogously to the zonal aggregation in the European electricity market). Further, the ability to restrict the net import/export balances of the locational hubs with linear constraints is necessary, in order to communicate to the market actors a feasible trading domain including reliability requirements (*e.g.*, the N-1 criterion or something more advanced) but also grid flexibilities of the transmission system, so as to avoid outcomes whose physical implementation is unrealistic. Finally, both trading at a portfolio level and/or a physical unit level are applicable options, provided that after the market execution the respective market actor communicates its physical schedules at a unit level and localized at the respective buses of the transmission grid. With reference to such physical schedules, all market actors should also be invited to offer their potential re-dispatch flexibility and cost thereof, in order to allow the coordinated use of all resources by the TSOs.

(b) Secure physical delivery

The security management phase is the most fitting context to exploit grid flexibility, given the less restrictive physical modeling domain (including non-convexities, non-linearities, static & dynamic behaviours to the extent necessary). The complications come from multi-area interconnection and therefore the important feature in the proposed framework is the mutually acceptable decision making between the several TSOs involved. We envision that the common mission of a group of cooperating TSOs should be to minimize deviations from the declared physical schedules of the market actors, while respecting the system-wide security criteria.

The system-wide security criteria should of course be defined in a harmonized manner by the group of cooperating TSOs and/or respective energy system regulators. The important feature in our framework is that each TSO should also bear the cost attributable to the restrictions corresponding to its control area. Within any control area the respective TSO should also unilaterally define and offer the available grid flexibility resources, and eventually be compensated if these resources create value outside its control area. Pointing to the following sections of the manuscript for the details of the respective cost/value calculation process, we argue that respecting the system-wide security criteria and following an agreed upon settlement process are conditions guaranteeing the cooperation of all TSOs towards implementing the mutually acceptable solution. The process of identifying such a mutually acceptable security management solution can either be administered by a central entity (in the role of multi-TSO coordinator) and/or implemented in a decentralized manner. In principle, both options allow for managing any privacy concerns in the exchange of information between the cooperating TSOs and are algorithmically feasible [3].

(c) *Ex-post* financial settlement

The general scope of the *ex-post* settlement process is to fully reimburse both the energy consumed by the system end-users and its secure delivery through the electricity network. We focus here on the latter, and the precise question of sharing the security management costs of a multi-area system at the inter-TSO level. Our proposal is based on the premise that each TSO may contribute both in a positive and in negative way to the minimization of security management costs.

To explain the negative contribution, let us notice that multi-area power system security management essentially amounts to spending money (activating control actions) in order to comply with the multi-area power system physical security limitations. Further, the multi-area power system physical security limitations are the features (*e.g.*, transmission capacities, resistances and reactances, import/export stability, *etc.*) of all control area sub-systems. Therefore, any single TSO may create a negative value to the group due to its respective part of the system physical limitations. To introduce the positive contribution, beyond the basic fact that electricity flows through the TSO operated infrastructure, we underline the role of grid flexibility. The ability to re-route power flows with grid flexibility resources can be used to achieve operational cost savings and operational reliability [12–14]. Therefore, any single TSO relieving part of the multi-area system security restrictions would create a positive value to the group.

On this basis, we argue for sharing the costs incurred to secure the physical execution of the electricity market transactions in a way that reflects the net contribution of each TSO in the multi-area power system. To do so, we propose to evaluate the contributions of each single TSO to the multi-area system security management by means of counterfactual analysis, as per the detailed methodology developed in section 3. Further, to allocate payments and revenues as per such valuations of contribution we propose the scheme detailed in section 4.

3. Evaluating TSO contributions to security management

This section presents the counterfactual analysis methodology proposed for evaluating the impact of each TSO on the multi-area power system security management problem. We formalize here the general principles of the methodology while abstracting away from the precise mathematical properties of the models adopted for its implementation as well as the precise criteria expressing the desirable system security level. A demonstrative implementation in the context of static N-1 security management is presented in section 5.

(a) Preliminaries & notation

To fix notation let us begin by denoting the state of the multi-area interconnected power system $(\mathbf{x})$. We considered that it is formed in consequence of (i) the forward market positions $(\mathbf{m})$, and, (ii) the activation of redispatch actions $(\mathbf{r})$, and, (iii) the activation of grid flexibility actions $(\mathbf{g})$, and (iv) the system parameters and physics. To abstractly represent the latter, we introduce function $\mathbf{x} = f(\mathbf{m}, \mathbf{r}, \mathbf{g})$ encapsulating all aspects within the scope of the security management problem.

We model the multi-area power system as a set of interconnected control areas $a \in \mathcal{A} \equiv [1, \ldots, A]$, corresponding to respective decision making agents (TSOs) responsible for security management. With this convention, the system-wide grid flexibility variable is a concatenation of area-specific control variable vectors, as in $\mathbf{g} = [g^1 \ \ldots \ g^A]$.

To model the mission of cooperative security management, we first define for each control area its set of secure states $\mathcal{X}^a$, expressing the admissible values for the multi-area system state variable $\mathbf{x}$ as per the intra-area security restrictions (*e.g.*, N-1 line overload constraints, voltage limits, system stability limits). Then, the security domain of the multi-area power system is the intersection of all area-wise sets of secure states[1]. In other words, managing the security of the multi-area power system amounts to choosing control actions so as to ensure that,

$$\mathbf{x} = f(\mathbf{m}, \mathbf{r}, \mathbf{g}) \in \bigcap_{a=1}^{A} \mathcal{X}^a. \tag{3.1}$$

The grid flexibility action space for the whole multi-area system is the Cartesian product of the area-wise action sets, as in $\mathbf{g} \in \bigtimes_{a=1}^{A} \mathcal{G}^a$. For redispatching variables, we explicitly denote the dependence on the respective forward market positions $(\mathbf{m})$ and symbolize the respective (system-wide) action space as $\mathcal{R}(\mathbf{m})$. Finally, taking the cooperative approach to security management concerns finding control actions across all system areas that are mutually acceptable by all TSOs. In compact notation, it suffices to express mutual acceptability in terms of (i) respecting all area-wise security limitations, and, (ii) a system-wide cost function to be minimized. Denoting the latter as $\mathbf{C}^{\mathcal{A}}(\mathbf{x}, \mathbf{r}, \mathbf{m})$ measuring the cost of redispatch deviations from the market participants forward positions, we pose the cooperative security management problem over the whole interconnected power system as finding,

$$\begin{aligned} (\mathbf{x}^\star, \mathbf{r}^\star, \mathbf{g}^\star) \in \arg\min_{\mathbf{r},\mathbf{g},\mathbf{x}} \mathbf{C}^{\mathcal{A}}(\mathbf{x}, \mathbf{r}, \mathbf{m}) & \\ subject\ to: & \\ \mathbf{x} = f(\mathbf{m}, \mathbf{r}, \mathbf{g}) \in \bigcap_{a=1}^{A} \mathcal{X}^a, & \\ \mathbf{g} \in \bigtimes_{a=1}^{A} \mathcal{G}^a, & \\ \mathbf{r} \in \mathcal{R}(\mathbf{m}). & \end{aligned} \tag{3.2}$$

(b) *What-if* analysis

Let us at this point re-introduce that the impact of any control area on the security management of the multi-area system can be considered as twofold. On the one hand, by way of its fixed physical properties in the system-wide physical model $f(\mathbf{m}, \mathbf{r}, \mathbf{g})$ and acceptable states in (3.1), any individual area may restrict the set of feasible solutions to (3.2). At the same time, by way of its grid flexibility decision variables in the left-hand-side of (3.1), any individual area may enlarge the set of feasible solutions to (3.2). The former impact can be understood as an **economic loss** (L_a) since reducing the feasible solution space may only lead to decisions of increased (at least, equal) economic cost in a minimization problem. Similarly, the latter can be understood as an **economic benefit** (B_a) since increasing the feasible solution space at negligible economic cost.

In order to compute these two quantities we apply counterfactual reasoning. More specifically, to quantify the economic loss per area we compare the cost of the full security management problem (3.2) to the cost of a problem relaxation (*i.e.*, larger set of feasible solutions) developed

[1]For notational simplicity, the set of cross-area interconnectors is treated as an additional control area here.

while doing away with the physical limitations of the area in question. In a similar manner, we quantify economic benefit by comparing the cost of the full security management problem (3.2) to the cost of a problem restriction (*i.e.*, smaller set of feasible solutions) developed while doing away with the grid flexibility of the area in question. Accordingly, we compute the net impact of every area to security management as:

$$N_a = L_a + B_a \quad \forall a \in A. \tag{3.3}$$

(i) Economic loss contribution

To compute the economic loss contributed by any single area, one needs to quantify the additional costs incurred by the multi-area cooperating TSO group due to the area physical and security limitations. In other words, the economic loss contributed by any single area is defined as the difference between the optimal objective of (3.2) and the system-wide cost resulting from the decisions all other TSOs would take if the transmission network of the area in question posed no restriction whatsoever.

To find such *what-if* decisions, we model a fictitious situation wherein the detailed transmission network model of the area in question is replaced by a fully controllable link to the area generation, loads and redispatch resources. To model an area as a fully controllable link (i) all generators and load are connected to a single *super-node*, and, (ii) the super-node is only linked with the buses connecting the original network to external areas through transmission paths of adjustable impedance. For demonstration, Fig. 1 exemplifies the reduction of a single area (transmission area A of the multi-area system shown in the upper part) into its ideal simplification. In the lower part of Fig. 1, all transmission links shown in black are to be modelled in full detail, whereas the links in area A shown in green are variable impedance and infinite capacity paths.

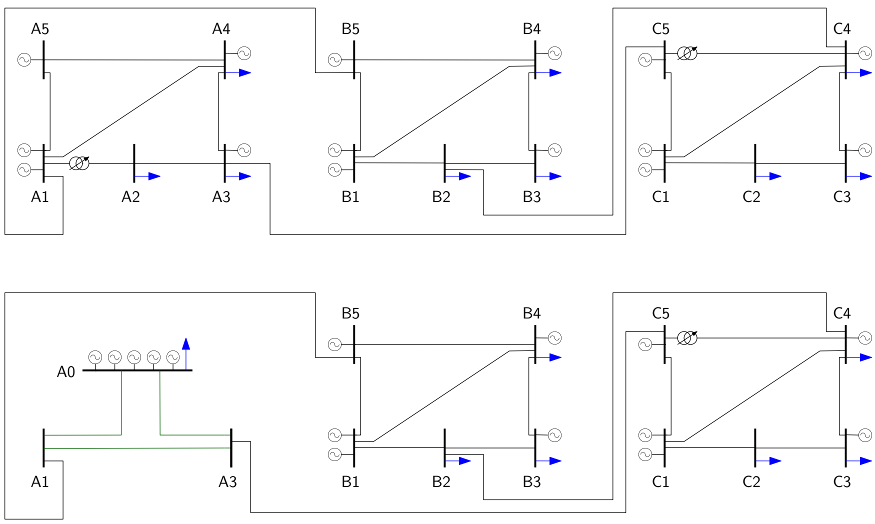

Figure 1. Ideal reduction of transmission area A

In the compact notation, we will employ symbol $u_{/a}$ to denote the variable impedances within any reduced area $a \in \mathcal{A}$ as well as function $\tilde{f}_{/a}\left(\mathbf{m}, \mathbf{r}, \mathbf{g}, u_{/a}\right)$ to denote the multi-area system physical model, when area (a) is represented by its controllable simplification. Further, we denote the respective security management decisions as $\left(\mathbf{r}^{\star}_{/a}, \mathbf{g}^{\star}_{/a}\right)$. We compute such decisions by stating and solving the relaxation of (3.2) as,

$$\left(\mathbf{x}^{\star}_{/a}, \mathbf{r}^{\star}_{/a}, \mathbf{g}^{\star}_{/a}\right) \in \arg \min_{\mathbf{r},\mathbf{g},\mathbf{x},u_{/a}} \mathbf{C}^{\mathcal{A}}\left(\mathbf{x}, \mathbf{r}, \mathbf{m}\right)$$
$$subject\ \ to:$$
$$\mathbf{x} = \tilde{f}_{/a}\left(\mathbf{m}, \mathbf{r}, \mathbf{g}, u_{/a}\right) \in \bigcap_{a'=1, a\neq a}^{A} \mathcal{X}^{a'}, \tag{3.4}$$
$$\mathbf{g} \in \bigtimes_{a'=1}^{A} \mathcal{G}^{a'},$$
$$\mathbf{r} \in \mathcal{R}(\mathbf{m}).$$

Notice that further from using the simplified physical model $\tilde{f}_{/a}\left(\mathbf{m}, \mathbf{r}, \mathbf{g}, u_{/a}\right)$, the security constraints from area (a) have been omitted in (3.4). Given the decisions corresponding to the full and relaxed multi-area security management problems, $(\mathbf{x}^{\star}, \mathbf{r}^{\star})$ in (3.2) and $\left(\mathbf{x}^{\star}_{/a}, \mathbf{r}^{\star}_{/a}\right)$ in (3.4) respectively, the economic loss contribution of any area is expressed as,

$$L_a = \mathbf{C}^{\mathcal{A}}\left(\mathbf{x}^{\star}_{/a}, \mathbf{r}^{\star}_{/a}, \mathbf{m}\right) - \mathbf{C}^{\mathcal{A}}\left(\mathbf{x}^{\star}, \mathbf{r}^{\star}, \mathbf{m}\right) \leqslant 0, \quad \forall a = [1, \ldots, A]. \tag{3.5}$$

(ii) Economic benefit contribution

To compute the economic benefit contributed by any single area, one needs to quantify the cost reduction gained by the multi-area cooperating TSO group thanks to using the area grid flexibility resources in a mutually acceptable manner. In other words, the economic benefit contributed by any single area is defined as the difference between the optimal objective of (3.2) and the system-wide cost computed with the baseline decisions the TSO would take if it was using its grid flexibility resources independently.

To find such *what-if* decisions, we model a fictitious situation wherein the TSO would be deciding autonomously and without any consideration for the physical properties and security domains of all external areas in the interconnected system. We do so for any single area with grid flexibility by solving a modified security management problem wherein the area of interest is the only intra-area network modeled in full detail and all other intra-area networks are reduced again to (ideal) controllable links. As an example, Fig. 2. illustrates the reduction of the multi-area system shown in the top part of Fig. 1 used to identify baseline grid flexibility decisions within area A.

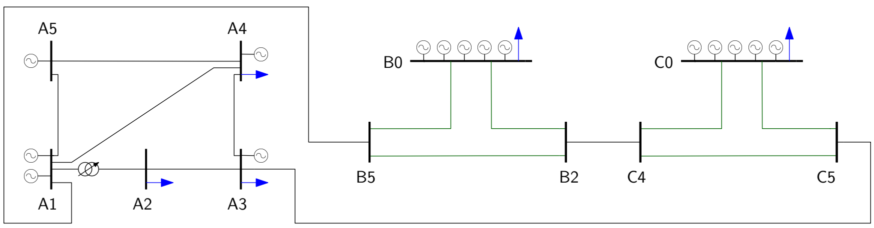

Figure 2. Ideal reduction from the perspective of transmission area A

In the compact notation, we will employ symbol $\bar{g}^a$ to denote the baseline intra-area grid flexibility decisions that would be taken independently by control area (a) as well as function $\tilde{f}_{+a}\left(\mathbf{m},\mathbf{r},\mathbf{g},u_{+a}\right)$ for the multi-area system physical model, when area (a) is the only area not represented by its controllable simplification (*i.e.*, the only area modeled in full detail). Accordingly, we find the baseline grid flexibility decisions per area by stating and solving the relaxation of (3.2) as,

$$\begin{aligned}
\bar{g}_a \in \arg\min_{\mathbf{r},\mathbf{g},\mathbf{x},u_{+a}} & \mathbf{C}^{\mathcal{A}}\left(\mathbf{x},\mathbf{r},\mathbf{m}\right) \\
& \textit{subject to}: \\
& \mathbf{x} = \tilde{f}_{+a}\left(\mathbf{m},\mathbf{r},\mathbf{g},u_{+a}\right) \in \mathcal{X}^a, \\
& \mathbf{g} \in \mathcal{G}^a, \\
& \mathbf{r} \in \mathcal{R}(\mathbf{m}).
\end{aligned} \tag{3.6}$$

Notice that apart from using the reduced physical model $\tilde{f}_{+a}\left(\mathbf{m},\mathbf{r},\mathbf{g},u_{+a}\right)$ only the security constraints for area (a) are considered in (3.6). It is necessary to acknowledge here that (3.6) provides baseline decisions while following an optimistic modeling convention. Particularly, it models the behavior of a single TSO enjoying full control (or rather, perfect collaboration) of all control-areas in its external grid. This convention is used here due to its simplicity/tractability advantage, as a first approach towards finding baseline decisions for modeling grid flexibility **only** in the cost allocation mechanism. It is of course of interest to explore alternative conventions, for instance the behavior of a TSO taking baseline decisions that would "protect" its intra-area grid even from the adversary behavior of the TSOs responsible for its external grid. Our overarching framework imposes no restriction on the assumption used to set the baseline decisions for modeling grid flexibility.

Moving on, we state the restriction to (3.2) when the grid flexibility decisions for any area a are fixed to the baseline values $\bar{g}_a$ as,

$$\begin{aligned}
\left(\mathbf{x}^\star_{+a},\mathbf{r}^\star_{+a},\mathbf{g}^\star_{+a}\right) \in \arg\min_{\mathbf{r},\mathbf{g},\mathbf{x}} & \mathbf{C}^{\mathcal{A}}\left(\mathbf{x},\mathbf{r},\mathbf{m}\right) \\
& \textit{subject to}: \\
& \mathbf{x} = f\left(\mathbf{m},\mathbf{x},\mathbf{r},\mathbf{g}\right) \in \bigcap_{a'=1}^{A} \mathcal{X}^{a'}, \\
& \mathbf{g} \in \bigtimes_{a'=1}^{A} \mathcal{G}^{a'}(\mathbf{m}), \\
& \mathbf{g}^{\mathbf{a}} = \bar{\mathbf{g}}^{\mathbf{a}}, \\
& \mathbf{r} \in \mathcal{R}(\mathbf{m}).
\end{aligned} \tag{3.7}$$

Problem (3.7) is a restriction of (3.2) with the additional constraint imposing that while solving the multi-area problem, the grid flexibility controls within area (a) must remain fixed to the baseline *what-if* decisions[2]. Given the solutions corresponding to the full and restricted multi-area security management problems, $(\mathbf{x}^\star,\mathbf{r}^\star)$ in (3.2) and $\left(\mathbf{x}^\star_{+a},\mathbf{r}^\star_{+a}\right)$ in (3.7) respectively, the economic benefit associated to any area is expressed as,

$$B_a = \mathbf{C}^{\mathcal{A}}\left(\mathbf{x}^\star_{+a},\mathbf{r}^\star_{+a},\mathbf{m}\right) - \mathbf{C}^{\mathcal{A}}\left(\mathbf{x}^\star,\mathbf{r}^\star,\mathbf{m}\right) \geqslant 0, \quad \forall a = [1,\ldots,A]. \tag{3.8}$$

[2]We emphasize this important additional consraint of (3.7) **in bold** by slight abuse of notation.

4. Inter-TSO settlement principle

Areas with a positive net contribution to security management would be areas that, by way of their intra-area transmission capacity and grid flexibility, bring a value to the multi-area interconnected system over and above the costs of maintaining them secure. These areas are effectively resources enabling the economic and secure operation of the multi-area system. On this basis, we propose an inter-TSO compensation mechanism that shares the total redispatching costs while also remunerating TSOs with positive net contribution.

In the proposed scheme, areas with positive net contribution are rewarded with an amount of money equal to their net contribution. Areas with negative net contribution share the augmented security management cost (*i.e.*, total redispatching costs plus remuneration towards positive contributing areas) pro-rata of the absolute net contribution. The inter-TSO settlement scheme is summarized in the following three steps, defining:

(i) the total positive net contribution as,

$$\mathbf{T}_{+} = \sum_{a=1}^{A} \max\{N_a, 0\}, \tag{4.1}$$

(ii) non-zero participation factors for areas with negative contributions as,

$$n_a = \frac{|\min\{N_a, 0\}|}{\sum_{j=1}^{A} |\min\{N_j, 0\}|} \geqslant 0, \tag{4.2}$$

(iii) revenues per area as,

$$P_a = \max\{N_a, 0\} - n_a \cdot \left[\mathbf{C}^{\mathcal{A}}\left(\mathbf{x}^\star, \mathbf{r}^\star, \mathbf{m}\right) + \mathbf{T}_{+}\right]. \tag{4.3}$$

A positive value of (4.3) corresponds to a revenue while a negative value corresponds to a payment. Further, only for areas with positive net contribution, the first term of (4.3) will be greater than zero while the second term, as per (4.2), equal to zero. Conversely, only for areas with negative net contribution, the first term of (4.3) will be equal to zero while the second term will be negative. Finally, we should underline that areas with grid flexibility and a negative net contribution would still be rewarded in the proposed scheme, by bearing a smaller share of the security management costs.

5. Demonstrative implementation

This section exemplifies the steps of our proposal and discusses its results through a demonstrative implementation. To facilitate result interpretability we consider a simple test-system inspired from the academic literature and focus on the well known application of N-1 steady-state security management. We retain a detailed analysis of the proposed scheme properties on alternative security management contexts and based on realistic multi-area systems as topics for future work.

(a) Test-case setup

We setup a three-area interconnected test-system with the one-line diagram shown in the top part of Figure 1. The starting point of each distinct area is the well known 5 PJM single-area case [15]. For the demonstrative purposes of our study, we have adopted the following modifications:

(i) three identical interconnector branches of impedance $0.003 + j0.028pu$ and permanent thermal rating $1.5pu$ are introduced to connect bus pairs [(A1,B5),(A3,C5)],(B2,C4)];
(ii) bus splitting/merging breakers are introduced at buses B2, B3 and B4 of transmission area B. The original load demand at these buses is shared by 50% on each side of the breaker;

(iii) the branch linking buses (A1,A2) in transmission area A and the branch linking buses (C4,C5) are replaced with *Phase-shifting Transformers* (PSTs) of equal impedance and thermal rating. The phase angle shift range of both transformers is 10°;
(iv) the marginal generation cost of each unit in transmission area A is increased by $\$200pu$ while the marginal generation cost of each unit at area C is reduced by $\$200pu$.

While modeling forward energy markets is beyond the scope of the demonstrative test-case, we adopt the following conventions without any loss of generality. First, we establish a market-based reference schedule for all generating units while considering every distinct area of the multi-area system as a distinct trading hub. More specifically, we solve a standard DC-OPF minimizing generation costs and while modeling the power flows, transmission capacity ratings and voltage angle difference limits for the three cross-area interconnection branches linking the three trading hubs[3]. Further, we assume that all generating units are online and that the respective market participants offer (i) the available head-room (*i.e.*, capacity - market dispatch) of each unit as upward redispatch resource, at the marginal generation cost of the unit, and (ii) the available floor-room (respectively, market dispatch - minimum stable generation) of each unit as downward redispatch resource for free.

(b) Security management application

We consider the steady-state N-1 security management decision making context by solving a standard DC-SCOPF problem.

The objective function of the problem seeks to minimize the cost of activating redispatch offers and the contingency set includes 20 events corresponding to the outage of any single branch or phase-shifting transformer, including the cross-area interconnectors. In preventive mode, the set of candidate decisions includes the redispatching of generating units, the position of bus splitting/merging breakers as well as the activation threshold for phase-shifting transformers. In corrective post-contingency mode, we model the (manual) modification of the bus splitting/merging breaker positions as well as the (automated) behavior of phase-shifting transformers, according to the respective activation threshold and rule-based operating modes [16]. For both problem stages, we impose network connectivity constraints on top of power balance constraints, active power flow constraints, and voltage angle difference constraints.

For reference, the total redispatch cost to achieve N-1 steady-state security taking advantage of grid flexibility is equal to $\$25038$ and omitting the grid flexibility resources would cause an additional cost of $+18.6\%$. Figure 3 plots the net import/export positions of the three trading hubs as per the forward market outcome (leftmost), the N-1 secure dispatch using grid flexibility and the N-1 secure dispatch omitting grid flexibility (rightmost). It is evident that grid flexibility has a value in reducing the deviations between forward financial transactions and secure physical delivery of energy. Finally, table 1 presents an overview of the network congestion (*i.e.*, active transmission constraints in the DC-SCOPF solution) with and without grid flexibility. For convenience, the entries corresponding to the system interconnection branches are shown in bold. One may notice that with grid flexibility the network would be congested in more (different) post-contingency states. This shows that the pre-contingency dispatch of the generating units is of more cost-efficient and making the most of the available transmission capacity under several different contingency network configurations. More importantly, notice the difference in the occurrence of congestion on the system interconnection capacity. Without grid flexibility intra-area congestion is more prominent, suggesting that the system interconnection capacity remains underutilized.

[3] In a real-life implementation, all TSOs may well also express their intra-area security domains to the market by means of proxy constraints which would encapsulate a part of the grid physical complexity. For instance, the flow-based approach in CWE already takes into account intra-area reliability targets as well as selected intra-area critical branches.

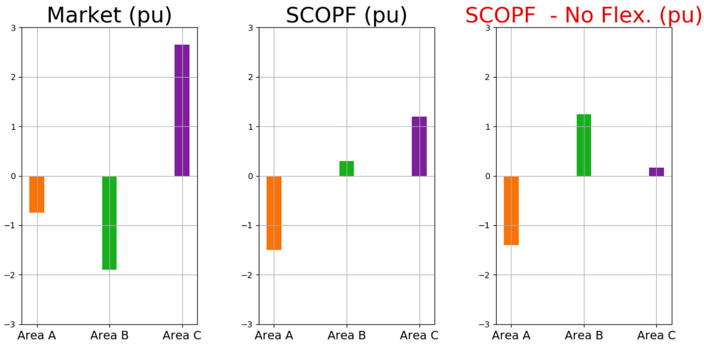

Figure 3. Net export positions per system area

No Flexibility		Grid Flexibility	
Contingency	Congestion	Contingency	Congestion
A1 – A4	A4 – A5	A1 – A5	A4 – A5
A1 – A5	A4 – A5	C1 – C4	C4 – C5
B1 – B4	B4 – B5	C1 – C2	C4 – C5
B1 – B5	A4 – B5	C1 – C5	C4 – C5; **A3 – C5**
A1 – A5	**A3 – C5**	B1 – B5	**A1 – B5**
		A3 – C5	**A1 – B5**

Table 1. Network congestion overview

(c) Counterfactual analysis of area-wise impacts

We begin with the results of the counterfactual analysis of the impact of the physical characteristics, security constraints and grid flexibility of all areas to the multi-area security management task.

Figure 4.a. plots the economic loss indicators for the three areas of the test-system. We recall here that these indicators measure the relative costs implied by the physical characteristics (*e.g.*, impedances, capacity ratings, topology, *etc.*) and security constraints of any single area. We notice first that area C has the smallest absolute value of economic loss. This is the area exporting the most, Figure 3, thanks to the available cheapest generation resources. The interpretation of the smallest economic loss indicator (*i.e.*, smallest difference in cost when neglecting the physical characteristics & security limitations of this area) relates to this fact. There is still a large security management cost to pay in order to get the cheap power coming out of area C to the loads located in areas A,B of the interconnected system. It is the cost of keeping areas A,B as well as the system interconnection capacity N-1 secure. Conversely, importing area A has the largest absolute value of economic loss. This loss is associated to the security of the intra-area transmission network between the loads in area A and the exporting areas B, C. Without this intra-area network, it would be much cheaper to securely serve the area A loads.

Figure 4.b. plots the economic benefit indicators for the three areas of the test-system. We recall here that these indicators measure the value of the grid flexibility inside each area to the multi-area system. We start again from area C to discuss the zero value attached to the PST inside this area. In our detailed results, we have noted that the settings of this PST that would be chosen independently by the area C TSO (assuming the ideal simplification of the rest of the network) match the settings of the PST from the solution of the full multi-area N-1 SCOPF. In other words the TSO of area C does not provide any grid flexibility to the multi-area system with this PST,

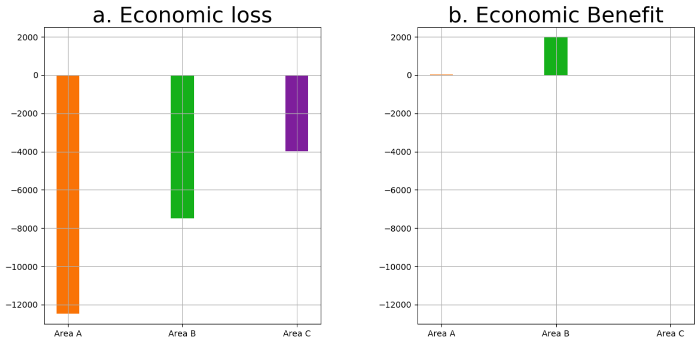

Figure 4. Economic impact indicators

Area A	Area B	Area C
-12463.78	-5517.98	-3935

Table 2. Net impact indicators per area ($)

meaning that the "global" value of this PST to the multi-area system is zero. The PST in area A has a small positive global value to the system. Neglecting the rest of the network, the TSO in area A would have set the activation threshold for this device to keep the flow at 21.1% of the respective rating. However, considering the security management of the full multi-area system the optimal setting is at 13.1%. The computed economic benefit value of $14.09 expresses the avoided cost thanks to this modified setting. Most notably, there is a large economic benefit value attached to the grid flexibility inside area B. We recall that it is possible to split 3 out of 5 buses inside this area. In our detailed results, we have noted that in the full multi-area N-1 SCOPF the bus breakers are in different position with respect to the optimal positions from the area B individual perspective both for the base case configuration (no outage) as well as in all credible contingency states.

(d) Security cost settlement

Table 2 presents the indicators quantifying the net impact of each area on security management. For the considered test-case all indicator values are negative, meaning that the economic loss associated to securing any area of the network is always larger than the economic benefit of the area flexibility. As a result, all three area TSOs should pay to share the $\$25038$ cost of the redispatching actions necessary to secure the multi-area system. The resulting allocation coefficients from (4.1 – 4.3) are pro-rata of the negative impact indicator values. Figure 5 presents the cost allocation coefficients. We notice the large share of the cost to be paid by (importing) area A, which was found to have the largest negative impact to the multi-area system security management cost.

To put these results in perspective, we have also repeated the whole computation for the case where there is no flexibility in the grid. We found that without grid flexibility area B would be allocated 36.2% of the increased multi-area security management cost. Further than the reduction of its cost share, this area of course benefits from the system security management cost reduction induced by grid flexibility, as demonstrated by the comparison in Figure 6. This result exemplifies how the proposed method provides a clear incentive to develop grid flexibility at locations with global value to the interconnected system. Notice the contrast with area A. For this area,

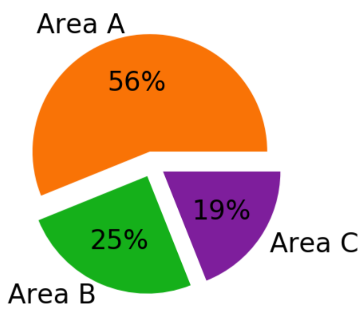

Figure 5. Security management cost allocation coefficients

the increase in the cost allocation coefficient in the case with flexibility outweighs the overall reduction in the total cost to be shared among the three system areas.

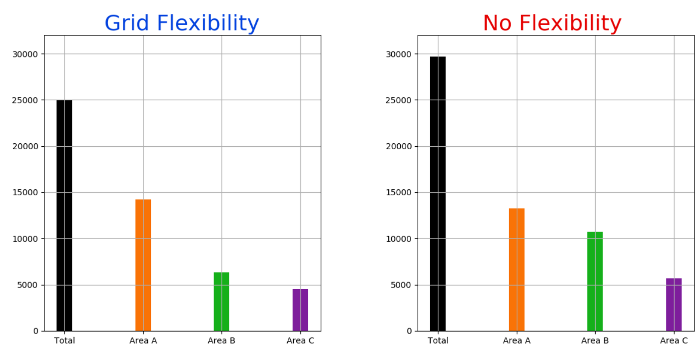

Figure 6. Security management costs ($)

6. Conclusions

This paper revisits the framework for the coordinated operation of a multi-area interconnected power system, with a view on making the most of the grid flexibility furnished by power flow controlling measures embedded in the transmission infrastructure. While the electricity market is a key instrument for coordination in modern power systems, grid flexibility remains unrepresented. The physical and mathematical modeling properties of this resource are well beyond the underlying assumptions of the electricity market rules and the scope of applicability of market clearing algorithms. On this premise, we argue for the coordinated deployment of grid flexibility in the post-market clearing stage of security management by cooperating TSOs of a multi-area system.

While the reasoning for the coordinated deployment of grid flexibility can be considered as evident, clear incentives to all involved stakeholders are necessary to put cooperation in practice. To this end, we introduced a new way for sharing the costs of multi-area security management at the inter-TSO level. The aim of our proposal is to share these costs in a way that reflects the contribution of every control area to the problem of keeping the multi-area system secure. More specifically, we argue for a cost allocation rewarding control areas whose intra-area grid flexibility globally helps alleviating congestion and/or penalizing control areas whose intra-area network parameters globally result in intensifying congestion. These rewards and penalties are meant as financial incentives promoting the coordinated, cost-efficient operation of a multi-area power system with grid flexibility.

To compute the cost-sharing rewards and penalties we developed an approach inspired by cooperative game theory. The key idea is to compare the cost of securing the multi-area interconnected system to hypothetical situations wherein (i) the intra-area grid flexibility of any single control area is not available for coordinated use and (ii) the intra-area network of any single control area poses no physical and/or security restrictions. The former *what-if* study can quantify the economic benefit value of the grid flexibility provided by each control area while the latter can quantify the economic loss originating from the design features of each control area. Accordingly, summing these two values quantifies the net impact of any control area on the system security cost. An important feature of this settlement scheme is that it imposes no additional limitation in modeling the physics of the power system. Indeed, the same process used to identify mutually acceptable decisions to secure the multi-area system is also integrated in the counterfactual *what-if* analysis for the impact of any single control area. Moreover, we underline that the proposed settlement process stays at the inter-TSO level. Each TSO could follow a local regulatory scheme to allocate this ex-post cost to the grid users. We could further also envision that energy market operators could propose hedging products related to these ex-post costs.

To exemplify our proposal, we relied on a demonstrative application to the problem of static N-1 security management for a fictitious three-area interconnected system. We designed such system with varying degrees of intra-area grid flexibility, as well as intra-area generation resources of different cost magnitude, for the sake of demonstrating the functionality of the settlement scheme. The results clearly showcase how the proposed scheme would reward intra-area grid flexibility, provided that it creates a global benefit for other external areas of an interconnected system. In other words, it would promote using intra-area grid flexibility in a cooperative manner. At the same time, the case study also exemplifies that the proposed settlement scheme would allocate a larger share of the multi-area system security management cost to a single individual area relying on imports of electricity through the rest of the transmission infrastructure (*i.e.*, a heavy user of the transmission infrastructure).

This paper served to (re-)open the discussion on evaluating grid flexibility by means of inter-TSO compensation. We believe that the topic is rather timely, given the widening integration of local electricity markets and the increasing uncertainties facing power system operation. On the basis of the work reported here, the following steps of this research will pursue the further development of our proposal. Going beyond the demonstrative application, we intend to study the computational efficiency of counterfactual analysis with respect to real-life interconnected power system security management applications. At the same time, going beyond the formalization of the main principles, we intend to analyze in detail the implications of potentially adopting the proposed settlement scheme at the inter-TSO level. Combining these parallel efforts will progressively allow to establish the utility of our proposal for promoting the cooperation necessary to efficiently operate modern multi-area power systems.

Data Accessibility. Please email Efthymios Karangelos (e.karangelos@uliege.be) to request all case study data.

Authors' Contributions. PP posed the research question and conceived the approach. EK and PP jointly specified the methodology. EK developed the demonstrative implementation, designed the case study and drafted the manuscript. PP reviewed and edited the manuscript. Both authors read and approved the manuscript.

Competing Interests. The authors declare that they have no competing interests.

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