EVALUATION FRAMEWORK FOR THE ASSESSMENT OF DIFFERENT TSO-DSO COORDINATION SCHEMES

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Abstract

This paper calls for a comprehensive evaluation of TSO-DSO coordination schemes (CSs) in the context of local flexibility procurement for balancing and congestion management services. The economic, regulatory, and technical implication of the different CSs should be considered. In this paper, particular focus is given to the economic pillar of the proposed methodology. By exploring the modelling of three CSs and the results from an illustrative case study, short and long-term economic conclusions are made. It is shown that CSs may lead to inefficiencies when markets are fragmented, and therefore liquidity is split. In addition, long-term economic aspects should be considered. Results show that the choice between distribution grid reinforcement versus local flexibility procurement is impacted by the CS in place. Finally, results demonstrate that central markets (e.g. balancing) can benefit from the participation of cheaper flexibility providers after the reinforcement of the distribution grid.

Nomenclature

Indices

$h \in H$	hour
$i,j \in N$	node
$g \in G$	generator
$f \in F$	flexibility service provider (FSP)
$s \in S$	system operator (SO)
$t \in T$	type of SO

Sets

H	Set of hours
N	Set of nodes
$L(i,j)$	Set of lines from node i to node j
G	Set of generators participating in the Day-Ahead (DA) market
F	Set of FSPs participating in the Ancillary Service (AS) markets
S	Set of system operators ($= \{T1 \dots Tn, D1 \dots Dn\}$)
T	Set of types of system operators ($= \{TSO, DSO\}$)
$TS(t,s)$	Set of correspondence between t and s
$SUBS$	Set of substations nodes ($SUBS \subset N$)
$FRONT$	Set of frontier nodes of a system operator ($FRONT \subset N$)
$IS(i,s)$	Set of nodes i belonging to System Operator s
$IG(i,g)$	Set of generators g connected at node i
$IF(i,f)$	Set of FSPs f connected at node i

Parameters

pQ_g^+	Maximum output of generator g in MW
pD_{ih}	Demand at node i in hour h in MW
pQ_f^+	Maximum output of FSP f in MW

pQ_f^-	Minimum output of FSP f in MW
pX_{ij}	Reactance of line (i, j) in p.u.
pP_{ij}^+	Maximum power flow of line (i, j) in MW
pP_{ij}^-	Minimum power flow of line (i, j) in MW $(= pP_{i,j}^+ * -1)$
$p\theta_i^+$	Maximum angle θ for node i in p.u.
$p\theta_i^-$	Minimum angle θ for node i in p.u.
$pBid_g$	Bid of generator g in the DA market in €/MWh
$pBid_f$	Bid of FSP f in the AS market(s) €/MWh
$pDispatchDA_{ih}$	Total generation cleared in the DA market produced in node i during hour h in MW
$pImb_{gh}$	Imbalance of generator g in hour h in MW
pSB	Base Power in MW

Variables

vP_{ijh}	Power flow in line connecting nodes i and j during hour h in MW
$v\theta_{ih}$	Angle θ at node i in hour h in radians
$vQDA_{gh}$	Quantity cleared in the DA market for generator g in hour h in MW
$vDispatchDA_{ih}$	Total generation cleared in the DA market produced in node i during hour $h\ in\ MW$
vQ_{fh}	Quantity cleared in the AS market for FSP f in hour h in MW
$vPSubs_{ih}$	Power leaving or entering substation $i \in SUBS$ in hour h in MW

Introduction

Power systems worldwide are experiencing important changes. Decarbonisation, digitalisation, and decentralisation are changing how electricity is produced, transported and consumed (Silvestre, 2018). These changes can also be extended to the way that system operators will operate their networks. Both transmission system operators (TSOs) and distribution system operators (DSOs) are facing challenges and observing opportunities coming from the new paradigm at power systems (Bell & Gill, 2018; Gómez San Román, 2017; Silva et al., 2018).

For the TSO, distributed energy resources (DERs) may be an additional agent participating in ancillary service (AS) markets and helping to improve power system cost efficiency. For the DSO, the opportunity to procure flexibility from DERs, which is now digitalised and more flexible (e.g. demand response, distributed generation, batteries, EV charging stations), offers a complete change in the distribution management paradigm. The DSO will be able to move from the “fit-and-forget” approach into an “active system management” position. By procuring DER’s flexibility, the DSO may defer or eventually avoid costly grid reinforcements.

Once TSOs and DSOs start buying and using DER flexibility, enhanced coordination between these two system operators will be needed (Lind et al., 2019). CEDEC et al. (2019) define five distinct service phases for a congestion management service, namely the (i) preparation and pre-qualification, (ii) forecasting phase, (iii) market phase, (iv) monitoring and activation phase and (v) the measurement and settlement phase. This classification can be used to understand when TSO-DSO coordination will be needed the most. Although enhanced coordination is expected to occur in all service phases, coordination at the market and monitoring/activation phases can be considered more challenging and critical. The level of coordination at the market phase will determine the economic efficiency of the flexibility procurement, while the coordination at the activation phase is necessary to ensure the security of the system. Focusing on the coordination at these two service phases, several publications have proposed coordination schemes (CSs) aiming at the efficient and secure procurement and activation of distributed flexibility by TSOs and DSOs.

Different literature reviews on the topic have already been published. Givisiez et al. (2020) classified over forty publications proposing CSs into three categories, namely (i) TSO-managed, (ii) TSO-DSO Hybrid-Managed, and (iii) DSO-managed market models. The classification looks at how the bid collection (market phase), the bid validation and the dispatch commands (monitoring and activation phase) are organised. Tohidi et al. (2018) and Tohidi & Gibescu (2019) also review the CSs proposed in the literature and identified four general CSs based on the roles of the TSO and the DSO in the operation of local and central markets. Both literature reviews highlight the effect of the hierarchy or sequence between system operators in the flexibility procurement, validation and activation. In Europe, a considerable part of the literature on TSO-DSO coordination is also being produced within research and innovation projects, testing such CSs in actual pilots. In 2019, six active Horizon 2020 European projects were exploring TSO-DSO CSs and data exchange in-depth, and several other projects touched on aspects of TSO-DSO interactions

(BRIDGE Initiative, 2019). Additionally, important pioneer projects were already concluded, such as the SmartNet and TDX-Assist, while others have since started as the OneNet project (Gerard et al., 2018; Radi et al., 2019; OneNet, 2020).

Besides showing the importance of the TSO-DSO coordination topic, the large volume of research developed so far also provides insights on the priorities for academia and practitioners. The BRIDGE Initiative report (2019) shows that, in terms of services, the vast majority of projects is exploring congestion management and balancing for TSOs (89% and 78% of projects, respectively), while 100% of projects are testing local congestion management and grid capacity management services for DSOs. Concerning timeframes, the vast majority focus on operational planning and real-time operation (86%), while only 14% of projects focus on the coordination at the network planning timestep.

In this paper, we focus on analysing TSO-DSO CSs for the procurement of DER's flexibility in the European context. Our main contribution is the proposition of a comprehensive evaluation framework for CSs, including not only short-term economic results, typically found in the literature, but also long-term economic effects of CSs, as well as technical and regulatory aspects. In this paper, special attention is given to economic aspects, which are tested on a small-scale model, providing numerical results for discussion. A regulatory discussion is also introduced in the conclusions.

Following this introduction, section 2 provides a description of the proposed framework. Section 3 describes the modelling approach for the three selected CSs. Section 4 provides the data for the case study, and section 5 the economic results. Finally, section 6 provides a policy discussion and concludes.

The need for a comprehensive evaluation framework for CSs

The modelling and evaluation of CSs have already been proposed by several authors, as shown in Givisiez et al. (2020). Nevertheless, modelling and testing different CSs is still an active area of research, as there is no consensus on the most suitable modelling techniques, considering the difficulties in adequately optimising the distribution portion of the TSO-DSO problem (Lind et al., 2019). Several authors focus on the description of the model, followed by illustrative case studies focused on the short-term economic results of the different CSs (e.g. the cost of DER activation for 24h), as in Papavasiliou & Mezghani (2018) and Savvopoulos et al. (2019). In this paper, we aim to complement this approach by proposing a more comprehensive method for evaluating CSs.

Together with the short-term economic results, long-term economic costs and benefits should also be considered. From the TSO's perspective, DER offers the possibility of having cheaper ancillary services as markets become more liquid and competitive. However, actions regarding network planning (e.g. distribution hosting capacity) may impact the amount of DER that can finally participate in the TSO's service markets. From the DSO's side, the procurement of DER flexibility is linked to the counterfactual of reinforcing the distribution grid. The main argument for DSOs to become active system operators is that by procuring and using distributed flexibility, costly network reinforcements can be deferred or even avoided. This argument has been recently translated into European regulation by the publication of the Electricity Directive within the Clean Energy Package (CEP Electricity Directive, 2019). Therefore, the interactions between network expansion planning, especially regarding the distribution grid, and the effects over different options of CSs should be considered.

The regulatory aspects of CSs should also be taken into account. As DSOs become more active, applicable CSs will have to comply with the expected roles and responsibilities associated with TSOs and DSOs. In Europe, this means that CSs must be in line with the provisions of the CEP and the Network Codes and Guidelines for operation and planning. Moreover, not only the European regulation must be considered, but also the national regulatory frameworks and the associated TSO-DSO landscape. Rules on wholesale markets and transmission system operation can be considered relatively harmonised in Europe, as wholesale energy markets are already integrated in a pan-European fashion. Balancing markets are now following the same path with their integration through regional initiatives (e.g. PICASSO for aFRR, MARI for mFRR), in accordance with the Electricity Balancing Guideline (EB Guideline, 2017). However, the DSO landscape in Europe is still very heterogeneous. It is noticeable how countries differ in the way the distribution grid is planned and operated. While some countries have only one DSO (e.g. Ireland and Greece), others have hundreds (e.g. Germany, Sweden, Spain) (Küfeoğlu et al., 2018). In addition, a single characterisation of what a DSO means in Europe is also difficult. The voltage levels that a DSO operates in Europe varies greatly, ranging from 20 kV up to 150 kV (Eurelectric, 2013). Other network aspects such as total line length, underground vs overhead lines and line percentages per voltage level differ considerably among countries (Prettico et al., 2021), suggesting that the topology of networks differs. Moreover, certain countries have a two-layer distribution system operation. For instance, in the case of Sweden, a local DSO connects to a regional DSO that finally connects to the TSO (Wallnerström et al., 2016). Therefore, the regulatory analysis in this research is twofold. On the one hand, the

European regulatory framework is analysed. On the other hand, the national regulatory and institutional landscape are considered.

Finally, a third pillar of the proposed methodology considers two technical aspects of CSs. Firstly, the technical scalability and replicability analysis of the CS is proposed. Initial academic evaluations of CSs rely on small-scale test cases. Similarly, the demonstrations done in pilot projects take place in limited geographical areas. Therefore, scalability and replicability analysis (SRA) based on simulations can aid to infer the expected results when solutions are deployed to large scale network as well as different locations (Rodriguez-Calvo et al., 2018). Secondly, the ICT requirements may also impact the viability of CSs. Aspects such as response time (latency), security and cost of the ICT infrastructure may be critical components for implementing different CSs (Kuusela et al., 2019; SmartNet Project, 2017).

Table 1 summarises the three proposed pillars for the evaluation of CSs. In the following sections, three CSs proposed by CEDEC et al. (2019) are modelled. A small case study is used to illustrate the evaluation of the economic pillar. A regulatory discussion is introduced in the final section of the paper. The technical pillar is not applied to the case study in this paper and will be examined in future work.

Table 1: CSs evaluation methodology divided into three main pillars

Pillar	Criteria	Type	Summary
Technical	Scalability of Coordination Algorithm	Quantitative and qualitative	Analysis of scaled-up networks and resources aiming at evaluating technical and economic barriers for the different CSs. Analysis of the deployment of different CSs to different networks (e.g. different types and different topologies)
	ICT complexity	Quantitative and qualitative	Analysis of response time (latency), security and cost of the ICT infrastructure involved in each CS.
Economic	Short-term cost of activation	Quantitative	Analysis of the cost of activation of DERs in the short-term (one day to one year).
	Long-term economic benefit	Quantitative	Comparison of cost and benefits of different CSs against possible network expansion planning decisions (e.g. reinforcement of constrained distribution assets).
Regulatory	Fitness to European regulation	Qualitative	Regulatory fitness of different CSs with respect to European regulation such as the CEP and the Network Codes.
	Fitness to national/regional TSO-DSO landscape	Qualitative	Regulatory fitness of different CSs with respect to national regulatory and institutional characteristics.

Modelling three TSO-DSO CSs

Market Sequence and CSs

In this paper, we model what aims to describe a stylised European market sequence, as described in CEDEC et al. (2019) and illustrated in Figure 1. This means that firstly, a wholesale market is run, clearing offers from buyers and producers for a 24h period. This market is here referred to as the day-ahead (DA) market, in reference to when it takes place in relation to the power delivery (real-time). This market, however, does not take into account any network constraints, assuming a copperplate network and simply matching the summation of the demand in each node for each hour with the merit order list of the generation. In this generic European market sequence, the results from the DA market are passed onto a System Operator (SO), in this case, the TSO and/or the DSO, which checks for the feasibility of that market-clearing. In case of network violations, the SO solves them by the use of congestion management markets. These markets act as redispatch markets, solving constraints by solving an optimal power flow (OPF) considering the results from the DA market, the offers from flexibility providers in the congestion management markets and the network limits and characteristics. This market takes place somewhen in between the DA and near to real-time timesteps. Finally, near to real-time, another market is cleared by the TSO, namely the balancing market. The purpose of this market is to compensate for possible imbalances between generation and consumption in real-time. In this paper, these imbalances arise from differences between what was offered in the DA market and what is delivered in real-time. The differences are considered to be forecasting errors. In the case of the generation, forecasting errors come from the RES generators (wind and solar errors in forecasting) and unexpected unavailability (total or partial), and for the demand, it comes from the retailers unable to perfectly predict the demand.

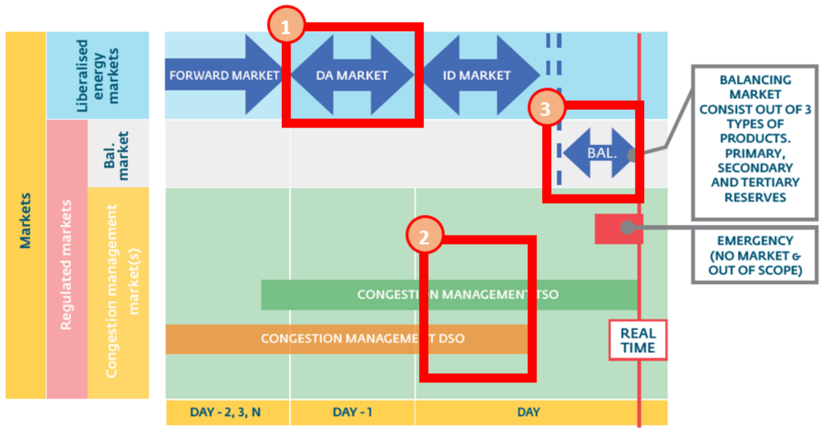

Figure 1: The sequence of electricity markets in Europe. Adapted from CEDEC et al. (2019)

Considering the market sequence above, three possible CSs are modelled. These CSs set how the TSO and DSOs organise the procurement of flexibility (active power) for balancing and for solving congestion management, both at the distribution and transmission grids. The three CSs are inspired in options 1, 2 and 3 proposed by CEDEC et al. (2019).

In option 1, the DSO runs a local congestion management market, while the TSO is responsible for the central congestion management and balancing markets, hereafter modelled as two separated markets, although they could be combined[1]. In option 2, a combined TSO and DSO congestion management market exists, while balancing is treated separately. In option 3, a central combined balancing and congestion management market is cleared. The three options are illustrated in Figure 2.

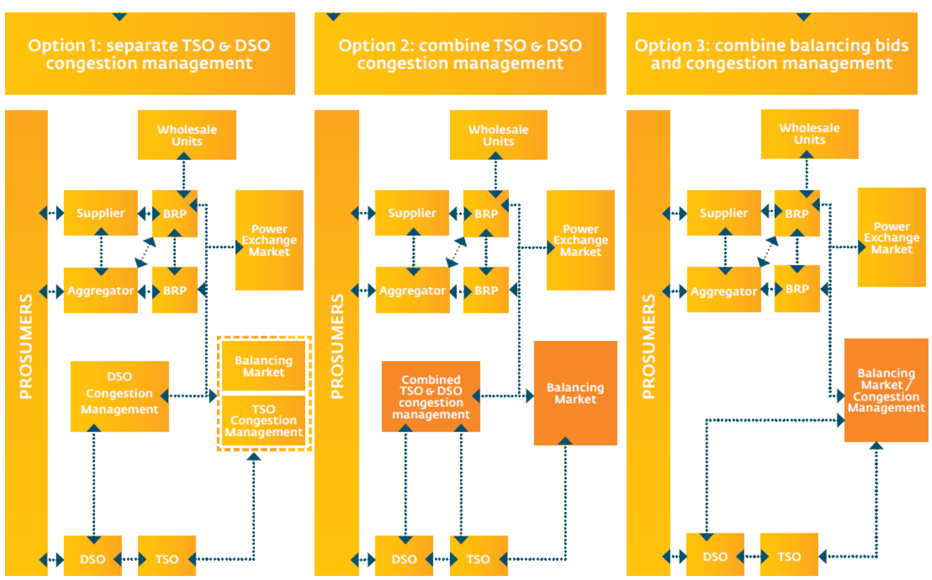

Figure 2: The three possible models for market coordination. Source: CEDEC et al. (2019)

In the following subsections, the mathematical formulation for the three coordination models is presented. This model will provide the basis for the economic evaluation in the following sections. In order to present the CSs in an ascending

[1] In CEDEC et al. (2019), the split congestion management and balancing scheme is referred as option 1a, while the combined congestion plus balancing as option 1b. For the sake of simplicity, we refer only as option 1, always in reference to option 1a.

complexity manner, the three options are described in reverse, from option 3 towards option 1. To model the three options, the work by Savvopoulos et al. (2019) is used as a reference.

Day-Ahead

The DA market stage is characterised by a simple clearing of the total demand in each hour and the merit order list of generation bids. At this market phase, the network is not taken into account. Therefore, the Market Operator (MO) minimises the generation cost (1), ensuring that the total demand is supplied (2) and that the maximum output of generators is respected (4). Equation (3) captures the total generation injected per node of the network, as this variable is later passed on to the AS markets as a parameter[2]. The DA market is common to all three subsequent CSs.

$$\min \sum_{gh} \left(pBid_g * vQDA_{gh} \right) \tag{1}$$

s.t.

$$\sum_i pD_{ih} = \sum_g vQDA_{gh} \qquad \forall h \tag{2}$$

$$vDispatchDA_{ih} = \sum_{g \in IG} vQDA_{gh} \qquad \forall ih \tag{3}$$

$$vQDA_{gh} < pQ_g^+ \qquad \forall gh \tag{4}$$

Option 3: Combined Balancing and Congestion Management

Following the DA market, the AS market(s) take place. In this option 3, it is assumed that the TSO is responsible for solving all imbalances and network congestions using resources connected at both the transmission and the distribution networks. This role could also be played by a third-party MO.

For this option 3, a single minimisation problem is solved, based on the "centralised AS market" in Savvopoulos et al. (2019). Equation (5) minimises the total cost of the flexibility service providers' (FSPs) activation during 24h. Considering that both congestion management and balancing markets in option 3 are centrally run by the TSO, the modelling of this CS can be seen as a single DC OPF. However, the demand balance equations (6)-(7) and the power flow equations (8)-(9) are split according to the type of SO[3]. In addition, equations (10)-(12) ensure that the power at the substation (the interface between TSO and DSO) is consistent. Finally, equations (13), (14) and (15) limit the capacity of the lines, the angles at each node, and the maximum output per FSP, respectively.

$$\min \sum_{s \in TS \wedge t = TSO, if h} \left(pBid_f * vQ_{fh} \right) + \sum_{s \in TS \wedge t = DSO, if h} \left(pBid_f * vQ_{fh} \right) \tag{5}$$

s.t.

$$\begin{aligned} pDispatchDA_{ih} + \sum_{f \in IF} vQ_{fh} - \sum_{j \notin SUBS} vP_{ijh} + \sum_{j \notin SUBS} vP_{jih} - \sum_{g \in IG} pImb_{gh} + vPSubs_{ih} \\ = pD_{ih} \qquad \forall i \in IS, s \in TS \wedge t = TSO, h \end{aligned} \tag{6}$$

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[2] $pDispatchDA_{ih} = vDispatchDA^*_{ih}$

[3] From a mathematical formulation perspective, TSO and DSOs are differentiated through different sets. For example, the demand balance equation (6) applies to all nodes associated to a SO ($\forall i \in IS$), for all SOs associated to a type of SO ($s \in TS$) and to which the type of system operator is a TSO ($\wedge\, t = TSO$).

$$pDispatchDA_{ih} + \sum_{f \in IF} vQ_{fh} - \sum_{j \notin SUBS} vP_{ijh} + \sum_{j \notin SUBS} vP_{jih} - \sum_{g \in IG} pImb_{gh} + vPSubs_{ih} = pD_{ih} \qquad \forall i \in IS, s \in TS \wedge t = DSO, h \tag{7}$$

$$vP_{ijh} = pSB * \frac{v\theta_{ih} - v\theta_{jh}}{pX_{ij}} \qquad \forall (i \in IS, j \in IS) \in L, (s \in TS) \wedge (t = TSO), h \tag{8}$$

$$vP_{ijh} = pSB * \frac{v\theta_{ih} - v\theta_{jh}}{pX_{ij}} \qquad \forall (i \in IS, j \in IS) \in L, (s \in TS) \wedge (t = DSO), h \tag{9}$$

$$vP_{ijh} = pSB * \frac{v\theta_{ih} - v\theta_{jh}}{pX_{ij}} \qquad \forall (i,j) \in L \wedge \big((i \in SUBS) \vee (j \in SUBS)\big), h \tag{10}$$

$$vPSubs_{ih} = \sum_{j \in SUBS} vP_{jih} - \sum_{j \in SUBS} vP_{ijh} \qquad \forall ih \tag{11}$$

$$\sum_{j} vP_{jih} = \sum_{j} vP_{ijh} \qquad \forall i \in SUBS, h \tag{12}$$

$$pP_{ij}^{-} < vP_{ijh} < pP_{ij}^{+} \qquad \forall (i,j) \in L, h \tag{13}$$

$$p\theta_{i}^{-} < v\theta_{ih} < p\theta_{i}^{+} \qquad \forall ih \tag{14}$$

$$pQ_{f}^{-} < vQ_{fh} < pQ_{f}^{+} \qquad \forall fh \tag{15}$$

Option 2: Combined TSO and DSO Congestion Management with separate Balancing

Option 2 is still characterised by a central MO, in this case, the TSO, solving congestions and balancing with resources connected at the distribution and transmission grid. The difference with respect to the previous option 3 lies in the fact that first, a congestion management market is run, followed by a balancing market. With regards to the bids of FSPs, it could be assumed that they bid independently in each market and that bids are not passed on as modelled hereafter. However, in order to model the independent biding, aspects such as FSP strategy would have to be considered, which lay outside the scope of this paper. Such aspects should be considered in future work.

Central Congestion Management Market

The congestion management market in option 2 is characterised by a DC OPF, similar to the one in option 3, differing by the fact that the demand balance equations (16)-(17) do not include the imbalances.

Min (5)

s.t.

(8), (9), (10), (11), (12), (13), (14), (15),

$$pDispatchDA_{ih} + \sum_{f \in IF} vQ_{fh} - \sum_{j \notin SUBS} vP_{ijh} + \sum_{j \notin SUBS} vP_{jih} + vPSubs_{ih} = pD_{ih} \qquad \forall i \in IS, s \in TS \wedge t = TSO, h \tag{16}$$

$$pDispatchDA_{ih} + \sum_{f \in IF} vQ_{fh} - \sum_{j \notin SUBS} vP_{ijh} + \sum_{j \notin SUBS} vP_{jih} + vPSubs_{ih} = pD_{ih} \qquad \forall i \in IS, s \in TS \wedge t = DSO, h \tag{17}$$

Following the congestion management market, minimums and maximums are adjusted and passed on to the balancing market, as demonstrated in equations (18)-(23).

$$pQ_f^{new+} = pQ_f^+ - vQ_{fh}^* \qquad \forall fh \tag{18}$$

$$pQ_f^{new-} = pQ_f^- - vQ_{fh}^* \qquad \forall fh \tag{19}$$

$$pP_{ij}^{new+} = pP_{ij}^+ - vP_{ijh}^* \qquad \forall (i,j) \in L, h \tag{20}$$

$$pP_{ij}^{new-} = pP_{ij}^- - vP_{ijh}^* \qquad \forall (i,j) \in L, h \tag{21}$$

$$p\theta_i^{new+} = p\theta_i^+ - v\theta_{ih}^* \qquad \forall ih \tag{22}$$

$$p\theta_i^{new-} = p\theta_i^- - v\theta_{ih}^* \qquad \forall ih \tag{23}$$

Balancing Market

In the balancing phase, another DC OPF is run by the TSO, this time including only the imbalances in the demand balance equations (24)-(25) and considering the new limits received from the congestions management market (26)-(28). Although the balancing market could be modelled without considering the network (replicating what happens in several balancing markets), the network is here included, as it is assumed that the TSO has full observability of the distribution network from the previous congestion management market in this option 2. Alternatively, the DC OPF for the balancing market might be seen as a proxy for what could be a longer market sequence, including another congestion management market very close to real-time.

Min (5)

s.t.

(8), (9), (10), (11), (12),

$$\sum_{f \in IF} vQ_{fh} - \sum_{j \notin SUBS} vP_{ijh} + \sum_{j \notin SUBS} vP_{jih} + vPSubs_{ih} = \sum_{g \in IG} pImb_{gh} \qquad \forall i \in IS, s \in TS \wedge t = TSO, h \tag{24}$$

$$\sum_{f \in IF} vQ_{fh} - \sum_{j \notin SUBS} vP_{ijh} + \sum_{j \notin SUBS} vP_{jih} + vPSubs_{ih} = \sum_{g \in IG} pImb_{gh} \qquad \forall i \in IS, s \in TS \wedge t = DSO, h \tag{25}$$

$$pP_{ij}^{new-} < vP_{ijh} < pP_{ij}^{new+} \qquad \forall (i,j) \in L, h \tag{26}$$

$$p\theta_i^{new-} < v\theta_{ih} < p\theta_i^{new+} \qquad \forall ih \tag{27}$$

$$pQ_f^{new-} < vQ_{fh} < pQ_f^{new+} \qquad \forall fh \tag{28}$$

Option 1: Separate TSO and DSO Congestion Management

In this option 1, firstly, the DSO runs a local congestion management market, followed by a transmission congestion management market, and finally, a central balancing market. Similar to option 2, in this CS, the new limits are passed on from one market to the next. In addition, the same assumptions with regards to FSP bidding from option 2 apply to this option 1.

DSO Local Congestion Management Market

In the local congestion management market, the DSO minimises the cost of activating resources connected at the distribution grid to solve local congestions only. The demand balance equations for this market (30) considers the results of the DA in terms of generation and demand for each node of the DSO's grid, plus the power expected at the interface with the TSO (primary substation).

$$\min \sum_{s \in TP \wedge tp = DSO, ifh} \left(pBid_f * vQ_{fh} \right) \tag{29}$$

s.t.

(9), (11), (12), (13), (14), (15),

$$pDispatchDA_{ih} + \sum_{f \in IF} vQ_{fh} - \sum_{j \notin SUBS} vP_{ijh} + \sum_{j \notin SUBS} vP_{jih} + vPSubs_{ih} = pD_{ih} \qquad \forall i \in IS, s \in TS \wedge t = DSO, h \tag{30}$$

TSO Congestion Management Market

The TSO congestion management market receives the remaining bids from the previous local congestion management market and solves congestion at the transmission grid using bids from flexibility providers located at both the transmission and distribution grids. Equation (31) ensures that the power at the interface with the DSOs is enough to cover what was scheduled in the DA market (not considering imbalances).

Min. (5)

s.t.

(8), (11), (12), (16), (26), (27), (28),

$$\sum_{i \in IS} pDispatchDA_{ih} - \sum_{i \in IS} pD_{ih} + \sum_{i \in IS, f \in IF} vQ_{fh} = - \sum_{i \in SUBS} vP_{i, j \in FRONT, h} \quad \forall (i \in FRONT) \wedge (i \in IS), (s \in TS) \wedge (t = DSO), h \tag{31}$$

Balancing Market

Finally, the balancing market run by the TSO solves imbalances in the complete network considering the new limits passed on from the previous two markets. In this market, the TSO uses the remaining bids from resources connected at both transmission and distribution grids. However, differently from the balancing market in option 2, in this case, the TSO does not consider power flows at the distribution grid, as in this CS, it is assumed that the DSO is responsible for local congestions, and therefore the TSO does not have full observability of the distribution grid. In this context, equation (32) ensures that the TSO covers the imbalances at the distribution network, assuming that no congestions are created.

Min. (5)

s.t.

(8), (11), (12), (24), (25), (26), (27), (28),

$$\sum_{i,f\in IF} vQ_{fh} - \sum_{i,g\in IG} pImb_{gh} = - \sum_{i\in SUBS} vP_{i,j\in FRONT,h} \, \forall (i \in FRONT) \wedge (i \in IS), (s \in TS) \wedge (t = DSO), h \qquad (32)$$

Case Study

In order to assess the long and short-term economic results for the three different CSs, an illustrative case study is used, based on the one in Savvopoulos et al. (2019), with few modifications described hereafter. The network comprises one five-node transmission grid and two eighteen-node distribution grids, as illustrated in Figure 3. Therefore, two DSOs (operating networks D1 and D2, respectively) are connected to one TSO (network TN in Fig. 3). The parameters for the distribution networks, including line capacities, reactances and distances, are the same as those described in Grady et al. (1991). The transmission network parameters can be found in Li & Bo (2010), with one modification, namely, the capacity of line T4-T5 is set at 325 MW. This modification creates congestions also at the transmission grid, justifying the necessity of a TSO congestion management market.

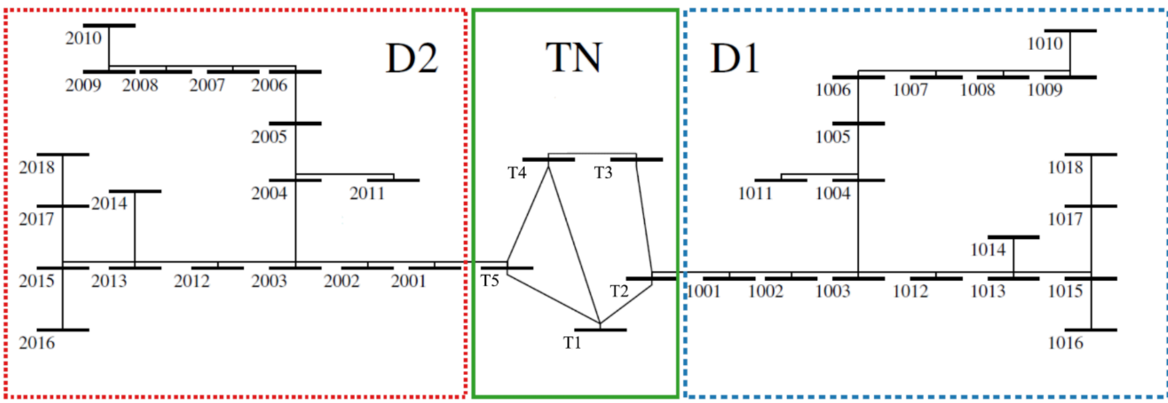

Figure 3: Case study network. Source: Savvopoulos et al. (2019)

Data regarding the DA market remains unchanged from the original source (Savvopoulos et al., 2019). This includes the generation units, prices offered in the wholesale market, and demands at each node. The original data is also used at the AS markets, including the imbalances from renewables and the FSPs participating in the AS markets. Nevertheless, two additional FSPs are included. One FSP is connected to distribution node D1015, while another is connected to transmission node T5. The former offers a symmetrical bid of plus or minus 20 MW at the price of 4 €/MWh, while the latter offers a symmetrical bid of plus or minus 30 MW at the price of 150 €/MWh. The added FSPs aim at showing the effect of having a cheap flexibility provider downstream a congested line (line D1013-D1015, as described below). These are the only FSPs offering symmetrical bids. The other FSPs offer either upwards or downwards bids, according to the original data. The model is implemented in GAMS language.

Results

Economic Results

The DA market results in a dispatch that would constrain lines D1013-D1015 and line T4-T5 during certain hours of the day, leading to the need for congestion management actions by the TSO and the DSO 1. After congestions are solved, imbalances are considered, as presented in Savvopoulos et al. (2019). Figure 4 illustrates congestions and imbalances to be solved in the AS markets.

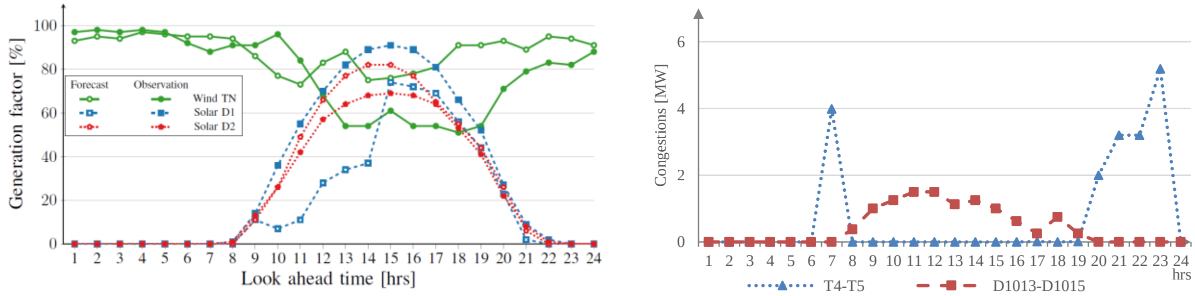

Figure 4: Imbalances and congestions. Source for imbalances: Savvopoulos et al. (2019). Source for congestions: own elaboration.

For the AS markets, in the three CSs (options 1, 2 and 3), simulations are run twice. Firstly, the case study is run as described above. On the second run, line D1013-D1015 is reinforced in order to compare the costs and benefits from using local flexibility against reinforcing the distribution asset. The reinforcement cost is calculated based on regulatory prices in Spain (Spanish Government, 2015). The average CAPEX for a 12 kV line is on average 75,000 € per kilometre. Based on this value, the distance of the line (Grady et al., 1991), a WACC of 5.58%, an asset life of 40 years, and utilising the annuity method, the depreciation and return on asset for the reinforcement is computed at 7,557 € per year. Table 2 presents the cost of activation for 24h for each option, as well as a cost-benefit analysis for the line reinforcement. In the case of the latter, the results for 24h are extrapolated according to three different assumptions on how many days the case study day might occur. Future work will consider representative days to better estimate for congestions and imbalance conditions throughout the year.

Table 2: Economic results for each option before and after distribution asset reinforcement

Cost of activation for 24h in €	**Option 1:** Separate TSO and DSO Congestion Management		**Option 2:** Combined TSO and DSO Congestion Management		**Option 3:** Combined Balancing and Congestion Management
	Congestion Management	Balancing	Congestion Management	Balancing	
1-TSO	1,873	487	1,973	487	2,395
2-DSO 1	44				
3-DSO 2					
Total		2,404		2,460	2,395
After distribution line reinforcement					
1-TSO	1,873	477	1,873	477	2,350
2-DSO 1					
3-DSO 2					
Total		2,350		2,350	2,350
Benefits from reinforcement in 24h		54		110	46
Benefits in one year	10 days scenario	541		1,101	457
	50 days scenario	2,703		5,505	2,283
	100 days scenario	5,405		11,009	4,565
Annual cost of reinforcement			7,557		
		Option 1		Option 2	Option 3
Benefits - costs (yearly)	10 days scenario	-7,017		-6,456	-7,100
	50 days scenario	-4,854		-2,052	-5,274
	100 days scenario	-2,152		3,452	-2,992

Considering the results of the three CSs before the reinforcement of the line, it is possible to observe that option 3, in which a single optimisation problem minimises the cost for all AS, is the cheapest. When balancing and congestion management markets are split (option 2), efficiency is lost, as FSPs are activated in opposite directions in the two markets. In contrast, in option 3 this situation is not observed (e.g. FSP@T4 and newFSP@D1015 in hours 12 to 15, in Figure 5). Therefore, the splitting of markets also splits the liquidity, reducing efficiency.

Considering the results before and after the reinforcement of the line D1013-D1015, a few conclusions can also be made. Firstly, the case study shows that benefits from reinforcing the constrained distributions asset are higher for less efficient CSs (e.g. option 2). If the congestions are recurrent (assuming that in 100 days per year, the case study situation is observed), it becomes more beneficial to reinforce the line than to procure flexibility. In the other scenarios and for the other CSs, it is more beneficial to procure local flexibility.

Another conclusion from the comparison before and after the reinforcement is that the balancing market becomes slightly cheaper once the distribution asset is reinforced. In the case study under analysis, this happens because cheaper units connected downstream the before-congested line can now participate in upstream markets offering cheaper flexibility, substituting more expensive FSPs (e.g. newFSP@D1015 replacing FSP@T4 during hours 10 and 11 after the reinforcement). Therefore, depending on how markets are split by the CSs under consideration, the long-term effects of reinforcements may affect liquidity and efficiency in upstream markets.

Figure 5: Dispatch by FSP for each option, before and after reinforcement of distribution asset

Conclusions and policy implications

This paper calls for a comprehensive evaluation of TSO-DSO coordination schemes in the context of local flexibility procurement for balancing and congestion management services. The economic, regulatory, and technical implications of the different CSs should be considered. In this paper, particular focus is given to the economic pillar of the proposed methodology. By exploring the modelling of three CSs and the results from an illustrative case study, short and long-term economic conclusions are made. Firstly, CSs may lead to inefficiencies when markets are fragmented, and therefore liquidity is split. Secondly, it is shown that the evaluation of distribution grid reinforcement versus local flexibility procurement is impacted by the CS in place. Finally, it demonstrates that central markets (e.g. balancing) can benefit from the participation of cheaper FSPs after the reinforcement of the distribution grid.

Based on these economic results and the characteristics of each CS (e.g. market sequence, product definitions), regulatory implications and CS fitness should also be considered. In particular, the setting of each CS should be analysed in light of the recent Clean Energy Package in Europe. In addition, the national TSO-DSO landscape should also be considered. In countries characterised by a large number of smaller DSOs (less than 100.000 customers), CSs in which market operation is delegated to the upstream SO may be more suitable, also considering that the general EU DSO regulation may not apply entirety for small DSOs. This regulatory analysis will be further developed in upcoming work.

This paper presents a work in progress and invites future work to further investigate the completion of a comprehensive TSO-DSO evaluation framework, contributing towards a cohesive methodology including and connecting the three proposed pillars. This includes exploring the ICT and SRA aspects here not covered and going deeper into the regulatory dimension, discussing topics such as the fitness of CSs to the European framework and conducting country-specific assessments.

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