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TSO-DSO Coordination

A multidimensional study on coordination schemes, modelling and regulation in the European context

by

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Declaration

I declare that this thesis was composed by myself, that the work contained herein is my own except where explicitly stated otherwise in the text, that no generative artificial intelligence models were used in any part of this work, and that this work has not been submitted for any other degree or professional qualification.

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Abstract

Power systems worldwide are experiencing deep changes. Among the main drivers is the decarbonisation of the energy sector. Summed to that, the electrification of other sectors (e.g. transportation), new opportunities for Demand Response (DR), and the digitalisation of the power sector set the landscape for a future with high shares of Distributed Energy Resources (DERs), posing challenges and opportunities for System Operators (SOs). All of these ongoing changes are calling for greater coordination between Transmission System Operator (TSO) and Distribution System Operator (DSO), especially concerning the procurement and activation of distributed flexibility by both SOs.

This thesis starts by arguing that, in the context of distributed flexibility procurement by both System Operators, four key elements are missing. They are: (i) the DER flexibility integration in balancing and congestion management markets, (ii) coordination schemes between TSO and DSO for the procurement of flexibility, (iii) transmission-distribution optimisation models, and (iv) data management and exchange.

Next, the thesis presents models for assessing different Coordination Schemes (CSs) in the context of distributed flexibility procurement used for balancing and congestion management at distributions and transmission grids. The proposed models focus on the coordination between the TSO and the high voltage distribution levels, introducing the meshed-to-meshed topology with multiple TSO-DSO interface substations. The models are applied to two realistic case study, namely the Swedish and the Spanish case studies. One-year period case studies based on real data are conducted, which are then subject to different sensitivity analyses. Results explore the concept of Non-Served Flexibility (NSF), and explore the capability for DSOs to solve congestions in different scenarios of available flexibility. In the Swedish case, for instance, results suggest that an increase of 10 GWh of activated flexibility per year would allow the incorporation of 145 GWh of demand without leading to an NSF situation for the DSO. This study also highlights the importance of the characteristics of Flexibility Service Providers (FSPs) participating in flexibility markets. In the Spanish case most of FSPs were non-controllable Distributed Generation (DG), limiting the capability to incorporate new demand solely through the use of flexibility, as DG can offer little or no upward flexibility. The modelling of different CSs also shows the a Common CS leads to lower flexibility procurement costs, while a different algorithms for the DSO's Local Flexibility Market (LFM) shows that a trade-off between flexibility procurement cost and market transparency and simplicity exists.

The thesis also proposes a bilevel model for the study of interface flow pricing. It considers a TSO-leader which sets interface prices freely, and DSO-followers in a Stackelberg game. This allows for the identification of regulatory risks and the testing of regulatory mechanisms. Based on two case studies, results show that a strategic TSO has the incentive to act so that the most economical flexibility providers are activated when compared to the first-best option, namely a Common TSO-DSO flexibility market. If left unregulated, however, it might also create important distortions in cost allocation. Leveraging on these results, a cap and floor mechanisms is proposed, showcasing that a Fragmented CS with dedicated incentives for the TSO could be an efficient second-best when compared to the Common CS and other regulatory options found in the literature. The conclusions from this study propose that a regulatory and price-based CS (namely a Fragmented CS with interface prices and TSO-driven incentives) can be an implementable TSO-

DSO CS, featuring reduced information exchange, low computational or Information and Communications Technology (ICT) needs, reduced regulatory supervision and good performance in terms of total flexibility procurement costs and cost allocation when compared to other alternatives.

Finally, a qualitative study on the structural and regulatory conditions is conducted. First, different flexibility-related Business Models (BMs) are identified and a comprehensive stakeholder consultation is conducted. Second, a regulatory country assessment is presented for eight European countries. Results show the existence of important barriers from both a stakeholders' perception perspective as well as from the regulatory frameworks from the different countries analysed. The analysis identifies that distributed flexibility exploitation by TSOs and DSOs are based on policy-driven markets, and that if institutional arrangements are not in place, resistance might exist from other stakeholders to integrated the necessary resources for flexibility provision. The regulatory analysis also shows that the implementation of CS that require information exchange or bid forwarding are still limited, especially in cases where the product is not harmonised. While balancing products and markets are mostly harmonised in all countries due to European regulation, congestion management products (if existent) are not harmonised, posing challenges to CS that require market timing synchronisation (e.g. Common CS) or some product harmonisation for bid forwarding (e.g. Multi-level).

This thesis concludes by providing an integrated assessment of the results obtained and the contributions made to the TSO-DSO coordination research field. Contributions are organised by the gaps identified in the initial literature review, arguing that the modelling of different CSs, LFMs and the qualitative analysis allowed for the identification of important characteristics necessary for system operator and FSPs for better integration of DER flexibility in current and future flexibility markets. Contributions are also made in the field of CSs and TSO-DSO modelling, especially with the introduction of novel bilevel model capable of testing of different regulatory mechanisms. The identification and investigation of incentive-based mechanisms for coordination is also highlighted as a key contribution. Future lines of research are also identified, including the expansion of realistic case studies to include complete subtransmission models, the inclusion of services other than overloads in the bilevel formulation and the testing of new and enhanced incentive-based mechanisms.

Resumen

Los sistemas eléctricos en todo el mundo están experimentando cambios profundos. Entre los principales impulsores se encuentra la descarbonización del sector energético. A esto se suma la electrificación de otros sectores (por ejemplo, el transporte), nuevas oportunidades para la Respuesta de la Demanda (DR, por su sigla en inglés) y la digitalización del sector eléctrico, configurando el panorama para un futuro con una alta participación de Recursos Energéticos Distribuidos (DERs, por su sigla en inglés), planteando desafíos y oportunidades para los Operadores de Sistema (SOs, por su sigla en inglés). Todos estos cambios en curso están exigiendo una mayor coordinación entre el Operador del Sistema de Transporte (TSO, por su sigla en inglés) y el Operador del Sistema de Distribución (DSO, por su sigla en inglés), especialmente en lo que respecta a la adquisición y activación de la flexibilidad distribuida por ambos SOs.

Esta tesis comienza argumentando que, en el contexto de la adquisición de flexibilidad proveída por recursos distribuidos por ambos Operadores de Sistema, faltan cuatro elementos clave. Estos son: (i) la integración de la flexibilidad de los DER en los mercados de equilibrio y gestión de congestión, (ii) esquemas de coordinación entre el TSO y el DSO para la adquisición de flexibilidad, (iii) modelos de optimización de transporte-distribución, y (iv) gestión y intercambio de datos.

A continuación, la tesis presenta modelos para evaluar diferentes Esquemas de Coordinación (CS, por su sigla en inglés) en el contexto de la adquisición de flexibilidad distribuida utilizada para el balance y la gestión de congestiones en las redes de distribución y transporte. Los modelos propuestos se centran en la coordinación entre el TSO y los niveles de distribución de alta tensión, introduciendo la topología de malla-a-malla con múltiples subestaciones de interfaz TSO-DSO. Los modelos se aplican a dos estudios de caso realistas, a saber, los estudios de caso sueco y español. Se realizan estudios de caso de un período de un año basados en datos reales, que luego se someten a diferentes análisis de sensibilidad. Los resultados exploran el concepto de Flexibilidad No Suministrada (NSF, por su sigla en inglés) y exploran la capacidad de los DSO para resolver congestiones en diferentes escenarios de flexibilidad disponible. En el caso sueco, por ejemplo, los resultados sugieren que un aumento de 10 GWh de flexibilidad activada por año permitiría la incorporación de 145 GWh de demanda sin provocar una situación de NSF para el DSO. Este estudio también destaca la importancia de las características de los Proveedores de Servicios de Flexibilidad (FSP, por su sigla en inglés) que participan en los mercados de flexibilidad. En el caso español, la mayoría de los FSP eran Generación Distribuida (DG, por su sigla en inglés) no controlable, lo que limita la capacidad de incorporar nueva demanda únicamente a través del uso de flexibilidad, ya que la DG puede ofrecer poca o ninguna flexibilidad a subir. La modelización de diferentes CS también muestra que un CS Común conduce a menores costos de adquisición de flexibilidad, mientras que diferentes algoritmos para el Mercado de Flexibilidad Local (LFM, por su sigla en inglés) del DSO muestran que existe un compromiso entre el costo de adquisición de flexibilidad, la transparencia y simplicidad del mercado.

La tesis también propone un modelo bi-nivel para el estudio de la fijación de precios de flujo en la interfaz. Considera un TSO-líder que establece precios de interfaz libremente, y DSO-seguidores en un juego de Stackelberg. Esto permite la identificación de riesgos regulatorios y la prueba de mecanismos regulatorios. Basándose en dos estudios de caso, los resultados muestran que un TSO líder estratégico tiene el incentivo de actuar para que los proveedores de flexibilidad más económicos se activen en comparación con la mejor opción, es decir, un esquema

de coordinación común. Sin embargo, si se deja sin regular, también podría crear distorsiones en la asignación de costos, por las cuales se crean transferencias desproporcionadas del DSO al TSO. Aprovechando estos resultados, se propone un mecanismo de límites superior y inferior a los precios de flujo en la interfaz, demostrando que un CS Fragmentado con incentivos dedicados para el TSO podría ser una opción eficiente en comparación con el CS Común y otras opciones regulatorias encontradas en la literatura. Las conclusiones de este estudio proponen que un CS regulatorio y basado en precios (a saber, un CS Fragmentado con precios de interfaz e incentivos dirigidos por el TSO) puede ser un CS TSO-DSO implementable, que presenta una reducción en el intercambio de información, baja necesidad computacional o de Tecnologías de la Información y Comunicación (TIC), menor supervisión regulatoria y un buen desempeño en términos de costos totales de adquisición de flexibilidad y asignación de costos en comparación con otras alternativas.

Finalmente, se realiza un estudio cualitativo sobre las condiciones estructurales y regulatorias. En primer lugar, se identifican diferentes Modelos de Negocio (BM, por su sigla en inglés) relacionados con la flexibilidad y se lleva a cabo una consulta integral de partes interesadas. En segundo lugar, se presenta una evaluación regulatoria por país para ocho países europeos. Los resultados muestran la existencia de barreras importantes tanto desde la perspectiva de percepción de las partes interesadas como desde los marcos regulatorios de los diferentes países analizados. El análisis identifica que la explotación de flexibilidad distribuida por parte de TSO y DSO se basa en mercados impulsados por políticas, y que si los arreglos institucionales no están en su lugar, podría existir resistencia de otras partes interesadas para integrar los recursos necesarios para la provisión de flexibilidad. El análisis regulatorio también muestra que la implementación de CS que requieren intercambio de información o envío de ofertas sigue siendo limitada, especialmente en casos donde el producto no está armonizado. Mientras que los productos y mercados de balance son en su mayoría armonizados en todos los países debido a la regulación europea, los productos de gestión de congestión (si existen) no están armonizados, lo que plantea desafíos para los CS que requieren sincronización en el momento del mercado (por ejemplo, CS Común) o alguna armonización del producto para el envío de ofertas (por ejemplo, Multi-nivel).

Esta tesis concluye proporcionando una evaluación integrada de los resultados obtenidos y las contribuciones realizadas al campo de investigación de la coordinación TSO-DSO. Las contribuciones están organizadas por las áreas identificadas en la revisión inicial de la literatura, argumentando que la modelización de diferentes CS, LFM y el análisis cualitativo permitieron la identificación de características importantes necesarias para el operador del sistema y los FSP para una mejor integración de la flexibilidad de DER en los mercados actuales y futuros. Se realizan contribuciones también en el campo de los CS y la modelización TSO-DSO, especialmente con la introducción de un nuevo modelo bi-nivel capaz de probar diferentes mecanismos regulatorios. Además se destaca la identificación e investigación de mecanismos basados en incentivos para la coordinación como una contribución clave. También se identifican futuras líneas de investigación, incluida la expansión de casos de estudio realistas para incluir modelos de distribución en alta tension completos, la inclusión de otros servicios en el modelo bi-nivel y pruebas de nuevos mecanismos regulatorios.

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1 Introduction

This chapter presents a background, motivation and objectives for this thesis. The outline is also discussed: besides this introduction, four self-contained chapters are developed, followed by a conclusions chapter. From a methodological perspective, this thesis can be seen as a multidimensional study. It contains both quantitative and qualitative components on different research domains.

1.1 Background

Power systems worldwide are experiencing deep changes. Among the main drivers is the decarbonisation of the energy sector, which has already led to shifts in the generation mix of many countries and will continue influencing policies and private investments. In the European Union (EU), for instance, a mandatory target of at least 42.5 % of renewable energy must be met by 2030 (European Commission, 2023b). As a consequence of decarbonisation, power systems are also bound to become more decentralized. Two-thirds of the installed renewable capacity in Europe is expected to be connected to the distribution grid (Silvestre, 2018). Summed to that, the electrification of other sectors (e.g. transportation), new opportunities for Demand Response (DR), and the digitalisation of the power sector set the landscape for a future with high shares of Distributed Energy Resource (DER), posing challenges and opportunities for System Operators (SOs) (MIT Energy Initiative, 2016).

Resources connected to the distribution grid already sell energy into wholesale markets, and are also starting to provide services to the management of the system. Additionally, distribution companies are expected to move from the "fit-and-forget" approach to the active management of the grid (CEDEC et al., 2019; Schwenen et al., 2013; Zhang et al., 2009). In fact, this shift is not only expected but also mandated by the European regulation, such the Clean Energy Package (CEP) (European Commission, 2019a). Flexibility from small DERs will be aggregated and offered to both distribution companies and transmission system operators to help in grid management (Bell and Gill, 2018). All of these ongoing changes are calling for greater coordination between Transmission System Operator (TSO) and Distribution System Operator (DSO), especially concerning the procurement and activation of flexibility from DERs by both SOs.

1.2 Motivation of the thesis

In this context of a change of paradigm for several actors (i.e., DSOs, TSOs, consumers), new research is needed in order to identify efficient and secure ways of incorporating these new solutions into the planning and operation of power systems. This includes an extensive scope of research, which covers several domains such as network expansion planning, flexibility market design, regulation of SOs, and Information and Communications Technology (ICT), to mention a few.

One argument made throughout this thesis, however, is that referring to "TSO-DSO coordination" is a simplification. Several types of TSO-DSO coordination will exist, as what a TSO and a DSO are vary greatly from country to country. As shown in Chapter 2 of this thesis, the SO landscape is not homogeneous in Europe, varying the number of SOs per country, their structure and the voltage levels they operate. If this is already a challenge in the European continent, where the legal definition for SOs is unified, this is even more challenging for other parts of the world in which different distribution-transmission legal and operation models exist, with different responsibilities and possibilities for the companies or institutions operating power networks.

On the one hand, an important field of research is the study of fundamental principles governing the different types of coordination and mathematical properties of different market design options. On the other hand, it is also important to consider real-world aspects of TSO-DSO coordination. This thesis aims at combining these two aspects. This is motivated by the fact that DSOs and TSOs are regulated companies with large and historical institutional arrangements in place due to the natural monopoly characteristic of network companies. Proposals for coordination that are myopic to these contexts might have their exploitation capabilities limited. Therefore, the aim of this thesis is also to be a bridge between theoretical and applied research.

In order to accomplish this objective of bridging fundamental TSO-DSO topics and real-world applied research, several boundaries have to be established to the research space in order to keep it tractable within this thesis. The first cut is the prioritisation of the investigation of TSO-DSO coordination in the EU. First, this allows for some degree of harmonisation in terms of institutional and operational arrangements, often dictated by regulation or legislation at the EU level. In addition, TSO-DSO coordination in the EU is already a pressing issue, materialised by the reiterated calls from European regulation and stakeholders for enhanced cooperation.

The second bound to the research space has to do with the topics covered in this thesis. While network expansion planning and ICT aspects of TSO-DSO coordination are equally important enablers and critical research areas, they lay outside the scope of this thesis. More objectively, this thesis focuses on *market design and institutional aspects for the efficient procurement and activation of distributed flexibility by TSOs and DSOs*. Furthermore, the thesis focuses on the procurement and activation of active power only, typically used in balancing markets or congestion management markets. Flexibility in terms of reactive power could also be procured by SOs, especially for voltage control. This type of flexibility, however, is not part of the focus of this thesis, as explored in the individual chapters.

1.3 Objectives of the thesis

The objective of this thesis is to identify efficient coordination schemes and conditions for TSOs and DSOs in the context of distributed flexibility procurement. Considering that distributed flexibility can be procured in different markets for different services, the objective is further defined to encompass primarily the congestion management and the balancing services. The option to focus on these specific services comes from the observation that they might be the first ones to embrace the participation of DER. On the one hand, balancing markets are already being opened to DER participation. On the other hand, DSOs are expected to procure flexibility in order to reduce or defer grid investments. Also, sector stakeholders recognise the importance of these two services for the early stages of TSO-DSO coordination needs. In a joint report, the European association of TSOs ENTSO-E and the DSO association (EDSO, CEDEC, Eurelectric, and GEODE) agree that balancing and congestion management should be tackled first:

> "*The reason to concentrate first on congestion management and balancing services provided by third parties is the importance of TSO–DSO coordination for these processes to ensure the security of supply. In a later stage, other elements or purposes of ASM [Active System Management] could be commonly investigated by DSOs and TSOs.*"
> (CEDEC et al., 2019)

Therefore, in this thesis, coordination schemes will focus specifically on congestion management and balancing reserves.

Main objective:

- Identify the efficient coordination schemes for TSOs and DSOs in the European context, with a focus on the coordination for congestion management and balancing reserves, based on modelling analyses.

Sub-objectives:

- Propose appropriate coordination schemes for the most common flexibility services in Europe, namely, congestion management and balancing. So far, most of the coordination schemes are still conceptual. They do not consider specific aspects of current service markets, neither some important regulatory principles. Therefore, this sub-objective aims at providing concrete coordination schemes for balancing and congestion management that could be implemented, considering the current and expected regulation in Europe.
- Develop/adapt optimisation model to test the proposed coordination schemes and inform regulatory analysis and recommendations. This sub-objective interacts with the previous one by testing the coordination schemes, validating them from a technical and economical point of view, and providing evidence for regulatory recommendations.
- Evaluate regulatory conditions for the flexibility procurement in Europe and their impact on the implementation of the different coordination schemes proposed.

1.4 Outline and contents of the document

In order to address the objectives above, this document is divided into six chapters. Besides this introduction, four self-contained chapters are developed, followed by a conclusions chapter. The four self-contained chapters could be read independently, and each one of them addresses a different aspect necessary to meet the above-mentioned objectives. From a methodological perspective, this can be seen as a multidimensional thesis. It contains both quantitative and qualitative components on different research domains.

Chapter 2 conducts a literature review as well as an assessment of the changes being currently observed in power systems and the reasons behind the need for enhanced coordination. It builds on top of the background and motivations of this introduction, identifying regulatory and structural changes calling for TSOs and DSOs to cooperate. It also assesses the scientific contributions to date on the field, focusing mostly on the literature revolving around the so-called Coordination Schemes (CSs). Finally, it identifies gaps that are explored in the following chapters.

Chapter 3 presents the first quantitative analysis of the thesis. This chapter models different CSs and analyses their properties in two realistic case studies, namely the Swedish and the Spanish case studies. These case studies are built based on both representative and real network data, also using real demand and generation data for one year. This chapter aims to reveal the real-world characteristics of flexibility procurement in the context of congestion management and balancing procurement. Attention is given to the modelling of a complete market sequence as well as different Flexibility Service Provider (FSP) characteristics. Another important characteristic of this chapter is that it considers the TSO-DSO coordination taking place at the Extra High-Voltage (EHV) to High-Voltage (HV) networks, as this is the most common type of TSO-DSO voltage level division in Europe. This means a meshed-to-meshed topology, which requires innovations in the modelling of the CSs. This applied quantitative research concludes by providing real-world data and insights on flexibility procurement by TSOs and DSOs.

Chapter 4 is devoted to a more theoretical quantitative research, exploring the pricing of interface flow variation. In parallel to the development of this thesis, research in the area of CSs showed that by optimally pricing the change of power flow on the TSO-DSO interface with respect to a previous schedule (e.g. the wholesale energy market), disjoint CSs such as the Multi-level or Fragmented can be as efficient as the first-best Common CS. However, the literature showed that computing the optimal price is not trivial. In chapter 4, a contribution is made to this field by first investigating what would be the incentives for the TSO when freely setting the interface price. This is done using a bilevel model, replicating a Stackelberg game in which the TSO moves first. Following this analysis, different regulatory mechanisms are tested, including one proposed in this thesis. Chapter 4 argues that a compromise between efficiency and cost allocation can be achieved by the use of regulatory mechanisms and incentives, providing a second-best for when the calculation of the optimal interface price is not a viable option.

Chapter 5 will depart from the quantitative analysis to offer a qualitative assessment on the conditions for TSO-DSO procurement of distributed flexibility and coordination. This is done on a multifaceted analysis. First, an identification of relevant business models for distributed flexibility (from both buyers' and sellers' perspectives) is conducted, followed by a stakeholder consultation on barriers and drivers on the different use cases. For this chapter, regulators, consumers, TSOs, DSOs and other stakeholders in different European countries were interviewed. Second, a country assessment on the conditions for TSO-DSO coordination is conducted, providing a picture of the implementability of different CSs for different flexibility services in eight European countries.

Chapter 6 is the concluding chapter. Based on the findings of the previous chapter, chapter 6 aims at providing integrated conclusions. Moreover, it also discusses the original contributions of this thesis, lists publications and identifies future research lines.

This thesis also contains four appendices. Appendix A provides an overview of baselining techniques for DERs, one of the missing aspects in the context of distributed flexibility procurement, as identified in 5. Appendix B provides a numerical example of how a decomposition technique can be used to implement a distributed and private Common CS. Finally, appendices C and D offer a complement to 4 by providing details on the linearisation process of the bilevel model and the full dataset for the use cases of chapter 4 and appendix B.

A graphical representation of the thesis outline is presented in Figure 1.1.

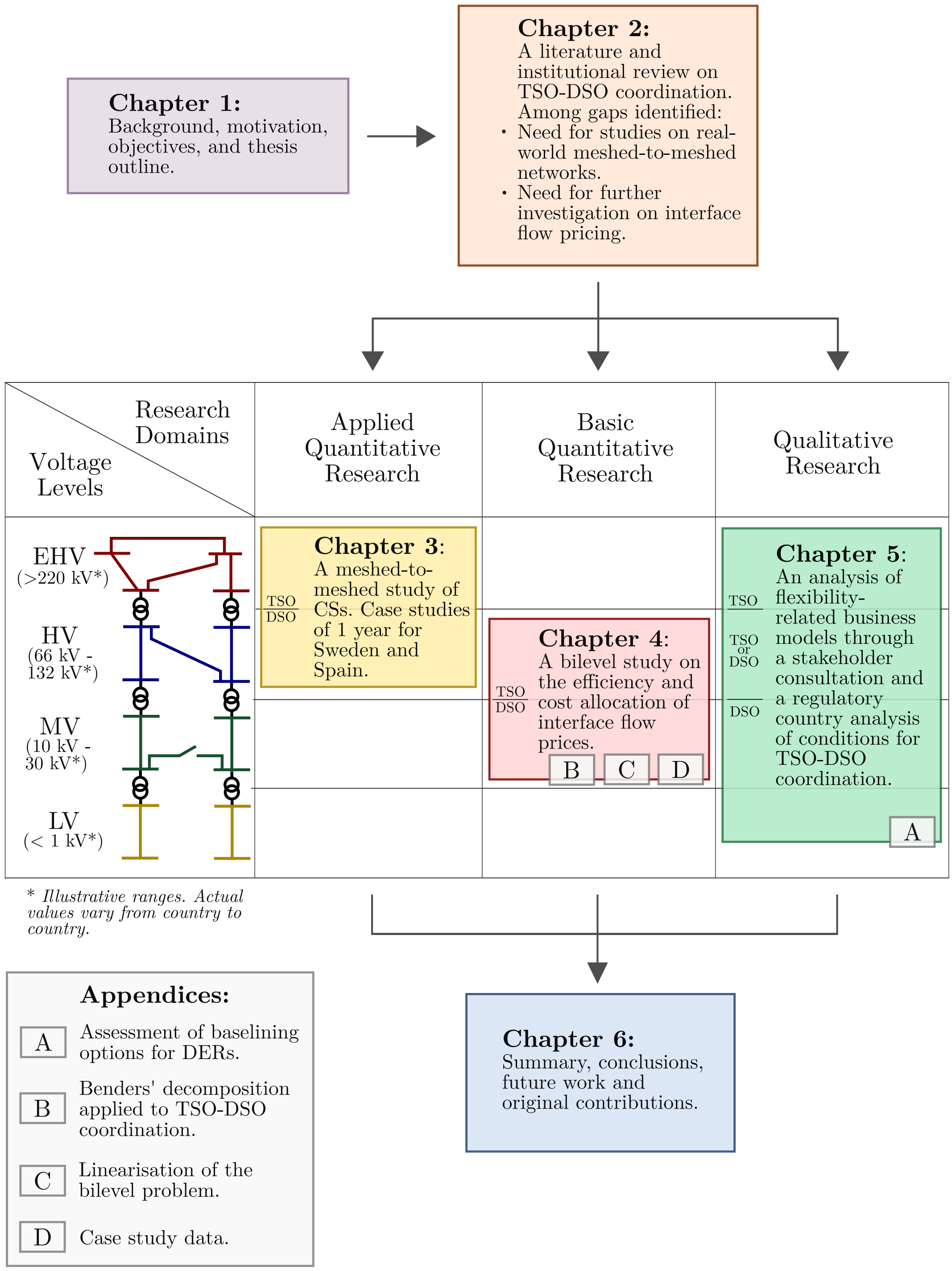

Figure 1.1: Thesis outline.

2 On the Need for Enhanced Coordination and the State-of-the-Art[1]

This chapter reviews the State of the Art of TSO-DSO coordination research. The main changes in power systems leading to the need for enhanced TSO-DSO coordination are discussed. Four missing elements enabling such coordination have been identified: (i) the DER flexibility integration in balancing and local congestion management markets, (ii) coordination schemes (CS) between TSO and DSO for the procurement of flexibility, (iii) transmission-distribution optimisation models, and (iv) metering data management models. Especial attention is given to the work on CSs, which concludes that research is still needed in order to identify techno-economical efficient and yet implementable CSs.

2.1 Introduction

This chapter provides a broad overview of several relevant issues regarding TSO-DSO coordination, mainly focused on the European context. The goal is to identify the reasons for the need for enhanced coordination, the identification of the key necessary elements for this coordination to happen, and the barriers found in the literature for each one of them.

Following this introduction, the first section of this chapter presents a historical context of the problem, as well as the causes of the need for TSO-DSO coordination. In the second section, the missing elements for coordination to happen are identified and discussed. Finally, conclusions are presented in the fourth section.

[1]This chapter is based on the following journal paper:

- L. Lind, R. Cossent, J. Chaves-Ávila, and T. Gómez San Román (2019a). "Transmission and Distribution Coordination in Power Systems with High Shares of Distributed Energy Resources Providing Balancing and Congestion Management Services". *Wiley Interdisciplinary Reviews: Energy and Environment* 8:6. ISSN: 20418396. DOI: 10.1002/wene.357

2.2 Towards a New Decentralisation

The power system operation has always been vital for the well functioning of the power sector, as electricity still must be produced and consumed instantly. The business of grid operators, however, is constantly evolving and eventually changing to adapt to new technological and regulatory landscapes. It is worth remembering that power grids start as small and not interconnected networks, in which generation was done locally in a decentralised fashion (Allerhand, 2017). However, in the pursuit of economies of scale and due to the fast demand growth, power systems began to grow and larger and interconnected networks emerged, especially after World War II (Smil, 2017). The growth in electricity consumption led to construction of larger power plants closer primary energy sources (e.g. hydropower plants, mine-mouth power plants) and far from the consumption centres, further requiring long-distance HV transmission lines.

From a financing perspective, the development of a large nation-wide power system could only be achieved through public financing, especially in the context of the post-World War II. Therefore, public Vertically Integrated Utilities (VIUs) became the viable economic model. This would be the norm in most countries until the liberalisation initiatives of the electricity sector in the '80s and '90s (Pérez-Arriaga, 2014). This liberalisation was accompanied by the unbundling process, meaning that VIUs should be separated by activity, namely generation, transmission, distribution and retailing. The first and the last are considered activities in which competition is possible and beneficial, while transmission and distribution are natural monopolies and therefore should be economically regulated.

Although the underlying assets of transmission and distribution companies may coincide in their function (e.g. power lines, transformers, switches etc), the TSO and DSO businesses and operation differ in important ways. Transmission businesses are characterized by few and large-scale facilities, while distribution has a much large variety of equipment and components, making these two businesses, although very similar in their objectives, very different in their planning and management.

Table 2.1 summarizes the key characteristics of transmission and distribution networks in terms of infrastructure, observability, and operation[2]. While transmission networks feature few and large-scale assets, distribution networks contain hundreds of thousands of equipment, and most of them are not monitored in real-time by distribution companies[3].

Conventionally, transmission and distribution activities were often carried out by the same company. A model based on regional VIU, under which the same company is responsible for generation, transmission, distribution and retailing, was the typical arrangement before the 1980s when power systems did not present competitive energy markets (Chawla and Pollitt, 2013). During the late '80s and early '90s, several power systems around the world began to be liberalised, and consequently, power network business started to be unbundled from the other activities in the electricity value chain. This process led to the separation of transmission and distribution companies. Nowadays, different unbundling models can be found for this purpose across the world. The most common approaches are the Independent System Operator (ISO) model, in

[2] The voltage levels operated by the DSO vary in Europe. The table presents the most common division according to Eurelectric (2020).

[3] As a reference, in the Spanish system, the transmission grid has approximately 3 thousand transformers while the distribution grid has more than 300 thousand transformers (Ministerio para la Transición Ecológica, 2022).

<table>
<tr><th colspan="2">Network</th><th>Infrastructure</th><th>Typical operation</th><th>No. of users</th><th>No. of transformers</th><th>Operation flexibility</th><th>Monitoring degree</th></tr>
<tr><td colspan="2">Transmission
(focus on the security of supply)
(Typically, 400, 275, 220kV)</td><td>Meshed</td><td>Meshed</td><td>Low</td><td>Low</td><td>High</td><td>High</td></tr>
<tr><td rowspan="3">Distribution (focus on quality of supply)</td><td>High-Voltage (132, 45, 66kV)</td><td>Meshed</td><td>Meshed / Radial</td><td>Low</td><td>Low</td><td>Medium</td><td>High</td></tr>
<tr><td>Medium-Voltage (20, 15kV)</td><td>Meshed / Radial</td><td>Radial</td><td>Medium</td><td>Medium</td><td>Low</td><td>Medium</td></tr>
<tr><td>Low-Voltage (400, 380V)</td><td>Meshed / Radial</td><td>Radial</td><td>High</td><td>High</td><td>Very low</td><td>Low*</td></tr>
<tr><td colspan="8">*Considering the monitoring of network assets (e.g. transformers) only, and not the final consumer metering.</td></tr>
</table>

Table 2.1: Typical characteristics of transmission and distribution networks in Europe.

which transmission assets are owned and maintained by one or more companies different from the system operator, and the TSO, in which the same company is responsible for both owning the assets and operating the system.

2.2.1 Current Power Systems

As of today, most of the transmission companies around the world are within a VIU, especially in those countries where there is no competitive market for electricity, according to the data published by Chawla and Pollitt (2013). In Europe, Belarus is the only country still in the VIU model. In Africa, Asia, and the Middle East, the VIU structure still prevails (Chawla and Pollitt, 2013). For those countries with unbundled transmission companies, North and South Americas are characterized by the ISO model, while in Europe the TSO structure is the most common.

On the distribution side, Küfeoğlu et al. (2018) offer a comprehensive and updated view of the distribution unbundling landscape, showing a very heterogeneous situation among countries. In Europe, for instance, some countries have very few DSOs, as it is the case for Northern Ireland (1), Ireland (1), Slovenia (1), Serbia (1) and Greece (2), while others have a large number of small DSOs, as Switzerland (900), Germany (875), Spain (340), and Czech Republic (290). The United States is the country with the most distribution companies in the world (3,112), according to the authors. The voltage levels operated by the DSOs also vary greatly. In the EU, most distribution companies operate low, medium and high voltage, as shown in Table 2.1. However, DSOs in six EU member states operate only low and medium voltage levels, namely Cyprus, Estonia, France, Hungary, Lithuania and Latvia (Eurelectric, 2020).

Other differences in the DSO concept in Europe also exist. It is not uncommon for a two-layer DSO to exist, meaning that a local DSO operating lower voltage levels (e.g. Low-Voltage (LV) and possibly Medium-Voltage (MV)) is connected to larger DSO which operates the higher voltage levels. This situation is observed in countries such as Spain, Germany and Sweden. In Spain, for instance, the more than 300 local DSOs are mostly connected to one of the five major distribution companies. In Sweden, the differentiation between local and regional DSOs is defined in their regulatory framework (Ruwaida et al., 2023).

This heterogeneity in the characterisation of TSOs and DSOs, especially the latter, poses challenges to CSs that may be proposed. In fact, this heterogeneity of TSO and DSO configurations shows that the TSO-DSO coordination is not a single problem, but a multifaceted one. While the TSO may have to coordinate with only a few DSOs, they might as well have to coordinate with several hundred. This coordination may take place on the EHV/HV networks in a meshed-to-meshed topology, or on the HV/MV networks, on a meshed-to-radial topology. Finally, a three-layer coordination may also be necessary, meaning a TSO that coordinates with regional DSO that finally coordinates with a local DSO.

2.2.2 New Paradigm: variable and distributed generation

Over the past two decades, two primary objectives have emerged as guiding factors in the power sector: the imperative for clean electricity and the promotion of competition in electricity markets. In Europe, the pursuit of renewable generation targets has incentivised countries to promote clean technologies, particularly wind power and Photovoltaics (PVs). This drive has resulted in cost reductions for these technologies, making it feasible for end-users to install Distributed Generation (DG) systems connected either directly to the distribution grid or behind consumers' meters. Additionally, the introduction of DR mechanisms and Electric Vehicles (EVs) is gradually becoming a reality. While these trends contribute to cleaner power systems, they also present challenges for sector management, particularly in terms of network planning and operation. Both TSOs and DSOs are experiencing the impacts of these changes.

On the one hand, TSOs have to deal with the higher variability and uncertainty generated by renewable generation. To address this new characteristic of generation, TSOs may have to procure additional system services to adjust the real-time demand-generation balance quickly (Brouwer et al., 2014; ENTSO-E, 2011; Holttinen et al., 2011). On the other hand, DSOs are facing an increasing number of generating units being connected to the distribution network. This is the case in Germany, for instance, where around 98% of the more than 1 million PV panels are connected to the distribution grid (Pérez-Arriaga et al., 2016).

2.2.3 The Rise of Distributed Energy Resources

Contrary to the conventional situation where distribution grids supplied mostly passive consumers and presented unidirectional power flows, the new paradigm is characterized by new types of resources connected to the distribution networks, which, at the same time, may provide services to the TSO. Therefore, it is important to define and enable the participation of these new resources.

The resources connected to the distribution grid can be generically identified as DERs. Within DERs, however, several different types exist. Firstly, a generator connected to the distribution grid is defined as DG. Secondly, active demand is also considered a DER, defined as DR. Thirdly, stationary storage systems are defined as Energy Storage System (ESS). Finally, the last type of agent is the EV, that acts as a type of ESS, but due to its potential importance and connection availability, it is considered separately.

Besides this classification, it is also important to consider where in the distribution grid the resources are connected. For example, a DG connected at HV level could be a wind farm of 10 MW or more of installed capacity, while a DG connected at the LV level can be a rooftop solar panel system with an installed capacity of 10 kW or less (Chaves-Ávila et al., 2020; IRENA, 2017). Therefore, these two DGs are clearly very different in terms of integration in the power system. While the former has characteristics similar to wind farms connected at transmission networks, the latter is significantly smaller and connected further down from transmission grid. The same can be said for DR being provided by a residential consumer or a large industrial consumer. Figure 2.1 summarizes the general definition of DER.

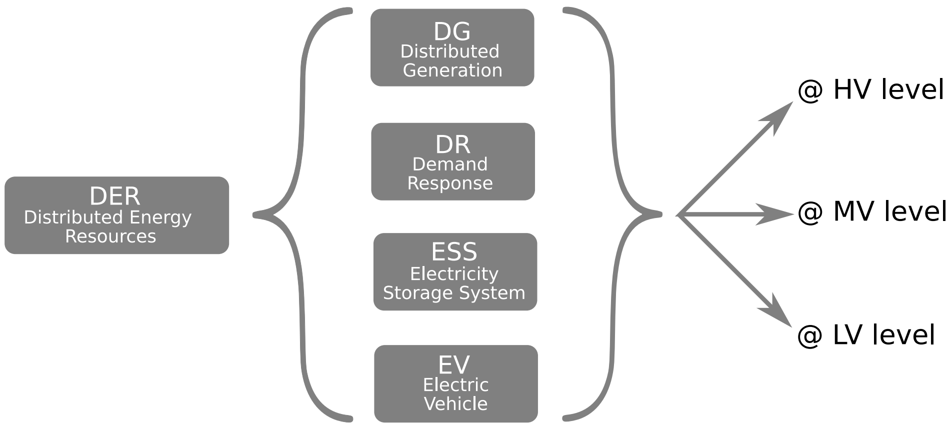

Figure 2.1: General Definition of DER.

2.2.4 New Roles for DSOs

The deployment of DERs will ultimately change how DSOs manage their grids. Indeed, DSOs will be able to carry out their "system operation" functions more actively, once the monitoring degree and operation flexibility increase in the distribution networks, i.e. distribution grids become "smarter".

Many European policymakers and stakeholders have already expressed their views on the upcoming roles of DSOs in the face of the new electricity paradigm. ACER (2014) highlights the need for DSOs to manage their networks actively, including the increasing need for cooperation between TSO-DSO. CEER highlighted five main aspects that should be improved, namely (i) a whole system approach, especially in network planning and investment, (ii) greater coordination between TSO-DSO in relation to the procurement of system services, operational and network planning/development/investment, (iii) data exchange between SOs, (iv) use of flexibility from DER, and (v) fairer cost sharing (CEER, 2014; CEER, 2015). Eurelectric (2016) also states its view for the roles of the DSO in the future, pointing out that DSOs will have a broader role as neutral market facilitator.

For DSOs, the new paradigm also brings opportunities. DERs may be able to provide services and contribute to the stability of the system. DSOs may use the flexibility of DER to solve voltage problems or manage congestions at the distribution grid. In fact, DSOs are expected to move from the “fit-and-forget” approach into active management of the grid (Ruester et al., 2014). This movement is also well defined by the CEP. The Directive on the internal market in electricity establishes several issues in which the DSO should act actively (European Commission, 2019a). That is the case for the procurement of services to improve efficiencies, including local congestion management and the definition of standardized products for such services.

Article 32 of the Directive 2019/944 states that DSOs “shall procure such services in accordance with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion” (European Commission, 2019a). The Directive also mentions the need for DSOs to “establish the specifications for the flexibility services procured and, where appropriate, standardised market products for such services at least at national level.” The CEP also defines what DSOs should not do. That is the case for the ownership, management, and operation of energy storage facilities. DSOs should not normally be allowed to carry out such activities according to the new European regulation. The text also pushes for third-party management of the charging stations for electric vehicles, allowing the DSO to carry out this activity only under certain criteria[4].

Besides the CEP, another important regulatory achievement in Europe is the implementation of the Network Codes. The Network Codes and Guidelines have introduced some specific roles for TSOs and DSOs, in order to ensure that both SOs have clarity on their responsibilities. It is the case for network and system planning, for data exchange between SOs, coordination in preparation and activation of corrective actions, coordination in pre-qualification and activation of DER (CEER, 2016a). The Network Codes also set the rules for cooperation among TSOs, which may serve as an example for the future cooperation between TSO and DSO (Hadush and Meeus, 2018).

Several academic sources and research projects also explored the new roles for DSOs (ACER, 2014; Batlle and Rivier, 2012; Kristov and De Martini, 2014; MIT Energy Initiative, 2016; Schwenen et al., 2013). Oosterkamp et al. (2014), for example, following a literature review and a public consultation, identify five main business opportunities for the future smart grids, namely: (i) flexibility services, (ii) infrastructure provision for EVs, (iii) energy efficiency services, (iv) ownership and management of metering equipment, and (v) data handling. The DSO would have a bigger role in metering and data handling. Following a similar classification, Pöyry (2015) investigates how such services are in place today for DSOs in the Nordic countries, including the provision of energy services, provision of energy efficiency measures, and participation in competitive activities. Rivero (2015) also envisions the potential roles for DSOs, as improving network planning and operation processes, contract and activate flexibility, data collection, storage and management, facilitate and enable electricity markets, and the management of smart metering infrastructure.

Whether DSOs will assume the foreseen roles also depends on which incentives they will be provided with. Several sources highlight the need for a revision in the way Capital Expenditure (CAPEX) and Operational Expenditure (OPEX) are incentivised, given the new cost struc-

[4] Although the CEP establishes that DSOs should not storage facilities neither own EV charging stations, exceptions may apply. For instance, DSOs can own and operate EV charging stations only if no company shows interest in offering this service after an open and transparent process. Storage facilities can also be owned by DSOs following the same principle abovementioned for EV charging stations, or if storage facilities are considered fully integrated network component (European Commission, 2019a).

ture DSOs will face (Bell and Gill, 2018; MIT Energy Initiative, 2016; Ruester et al., 2014; Schwenen et al., 2013). Investments to connect DERs may increase costs, while the active management of networks may decrease the total costs of DSOs. Batlle and Rivier (2012) also observe that, in the long term, investment costs should be reduced or at least postponed, given the ability DSOs will have to manage consumer demand at peak times. Therefore, Bell and Gill (2018) argue that the Total Expenditure (TOTEX) approach can provide the necessary incentives for DSOs to choose a cheaper operational solution, such as procuring DER's flexibility, as opposed to a more expensive asset-based one. Regardless of the final approach chosen, regulators will need to design mechanisms capable of equalizing incentives for CAPEX and OPEX savings, so that DSOs make use of the potential offered by flexible DER (MIT Energy Initiative, 2016).

Grey Areas for DSOs

In general, the activities carried out by DSOs should be easily identifiable, considering that DSOs are regulated companies and should not get involved in services of competitive nature. CEER (2014), for instance, presents a general framework to guide the decision on whether DSOs may be allowed to carry out a new activity. According to this framework, illustrated in Figure 2.2, DSOs may be allowed to enter new activities essentially if competition is not possible (arrow "I"). If competition is possible, they still may be allowed subject to certain conditions, and only if a proper justification exists (arrows "II" and "III").

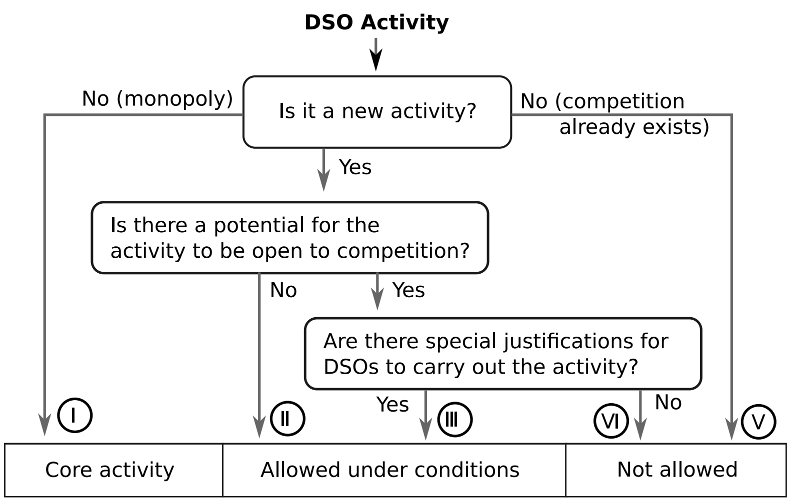

Figure 2.2: Logical Framework for DSO Activities. Source: CEER (2014).

Since the publication of the framework originally proposed by CEER (2014), many aspects of the new roles have started to be defined, notably with the publication and development of the CEP which kicked-off in late 2016. Nevertheless, several topics fell into the "allowed under conditions" category, illustrated by arrows "II" and "III" in Figure 2.2, putting such topics into a "grey area" for the new roles of DSOs. "Grey areas" for DSOs can be classified into two categories: (1) ownership of new infrastructure, and (2) data management.

New types of network users are appearing in power systems, many of which are connected mainly to the distribution grids. The role of the DSO in relation to the deployment of these new types of infrastructure is not completely clear yet. That is the case of battery storage systems and EV charging stations. In Europe, the main guideline for the ownership and operation of these infrastructures is the CEP referred above. As mentioned before, Article 36 of the Energy Directive sets the principles for ownership of storage facilities and states that DSO should not own, develop, manage or operate them in principle. However, if there are no investors interested in this type of assets, or if they are deemed necessary for grid operation (considered a fully integrated network asset), DSOs may be allowed to own storage facilities. This however, opens the possibility for Member State (EU)s (MSs) to interpret the European Directive in different ways. In fact, some countries have opened the possibility for DSOs to own/operate ESSs under certain criteria. In Hungary, for instance, the DSO can operate ESSs, provided that the asset is not used for congestion management and does not surpass 0.5 MW of installed capacity (Lind et al., 2021d).

The development and ownership of EV charging stations is also generally prohibited to DSOs. However, exceptions exist. According to Article 33 of the same Energy Directive, DSOs may be allowed to conduct this activity if other parties do not express their interest in a public tender.

Metering data management is another topic that has no clear definition for the roles of the DSO. While the DSO is usually the responsible for smart meter deployment and metering, the data storage and access might be done in different ways. According to CEER (2016b), data access and management models could be classified into three groups:

- A fully centralised model is the one in which all data is retrieved, validated, stored, protected, distributed and accessed by a single actor, i.e., the data hub.
- A partially centralised model involves the centralisation of some aspects, such as distribution and access to data. The storage, validation, and protection, however, would be organized at different locations within the DSOs systems and metering points.
- A decentralised model is the one in which the DSO is responsible for all the data activity through non-standardized procedures. In this model, all agents would have to interact and request data to the DSO in different ways, depending on the data.

As of today, countries in Europe are opting for different data management models, some adopting central data-hubs, whilst others maintain the decentralised model operated by the DSO (CEER, 2016b). For instance, countries like Poland, Austria, the United Kingdom (UK) or the Nordic Countries have opted for a centralised data-hub, Portugal, Spain, France or Italy remain relying on a decentralised model. The CEP does not advocate for one specific model, as long as data protection and access rules transparency are ensured (European Commission, 2019a).

Impact on SO tasks

A key objective of the aforementioned Network Codes is the implementation of integrated European balancing markets. Most of the Day-Ahead (DA) markets in Europe are already integrated (Newbery et al., 2016). Intraday (ID) integration has been implemented with the European Cross-Border Intraday (XBID) platform (OMIE, 2018). Balancing markets were the next. The

Network Codes and Guidelines, more specifically the Electricity Balancing Guideline (EBGL) define tasks and timelines for the implementation of European platforms for the exchange of balancing energy (European Commission, 2017b). Several test platforms were implemented for different balancing services, as for primary frequency regulation (Frequency Containment Reserves (FCR) Cooperation), secondary regulation (PICASSO platform) and tertiary regulation (MARI and TERRE platforms). These platforms allow for the cross-biding zone trading of balancing services, although not all countries participate in every platform.

Balancing markets will have to be adapted not only to incorporate the new European platforms but also to accept the agents willing to provide these services. Traditionally, balance service providers have always been comprised of large generating units. However, the decentralisation of generation will allow new agents to provide this service. Independent aggregators, prosumers and demand are a few examples of new balancing service providers. As of today, there are still very few independent aggregators engaging with residential consumers (Meeus and Noucier, 2019). The conditions for their participation in system service markets such as balancing are equally reduced. On the participation of the demand response in balancing markets, progress is being made with several countries already allowing demand participation, although conditions for participation are still not always sufficient (e.g. minimum bid size, complex ICT infrastructure required) (smartEn, 2018).

2.2.5 On the need for TSO-DSO Coordination

The deployment of smart grids and the new roles of DSOs are some of the changes taking place in the power sector that will call for greater TSO-DSO coordination, but not the only ones. Transformations are taking place at every step of the electricity value chain, from the centralised generation to the final electricity user. On the centralised generation side, the increase of variable and uncertain renewables is increasing the need for flexibility for TSOs (Brouwer et al., 2014; ENTSO-E, 2011; Holttinen et al., 2011). On the DSO side, the new roles and the active management of the grid will also call for coordination, as DSOs will also be interested in procuring flexibility from DER. Finally, end users are promoting the rise in DER usage (including ESS and EV).

The active management of the distribution grid will not only allow the integration of a larger number of DERs into the system but may potentially reduce total costs of distribution companies, as investments may be substituted by services provided by DERs to the DSO. At the same time, DERs may also provide services to TSOs through their markets (i.e. balancing, congestion management).

Figure 2.3 summarizes the above-mentioned changes taking place in power sectors. At every different step of the electricity value chain, novelties are taking place, each one of them leading to consequences that, in the end, will call for greater coordination between TSO and DSOs. In Figure 2.3, blue boxes represent novelties, while green boxes represent consequences from the identified novelties leading to the need for enhanced TSO-DSO coordination.

TSO-DSO coordination is already a concern for academia and policymakers. Policymakers, for instance, have already stated the need for TSO-DSO coordination, such as in Article 57 of the CEP Electricity Regulation, calling for cooperation between distribution system operators and transmission system operators (without specific definitions, however) (European Commission, 2019b). More recently, the Draft of Network Codes for Demand Response presents more def-

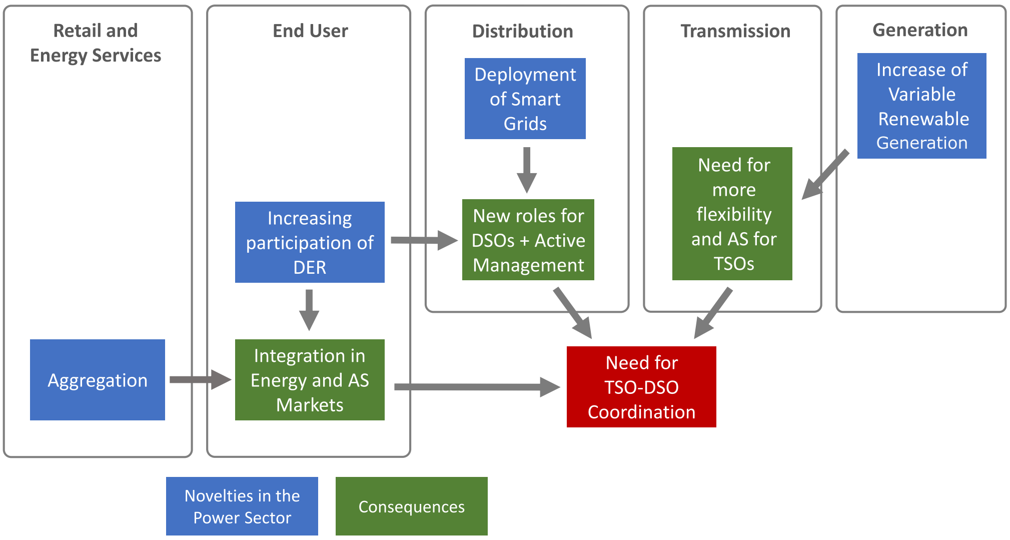

Figure 2.3: Reasons for the need for increased TSO-DSO Coordination.

initions, as discussed in chapter 5 (European Commission, 2023a). However, the definition of specific coordination mechanisms is yet to be defined in national regulatory frameworks.

Although it seems clear that coordination must be enhanced, the understanding of what is "coordination" varies in the literature. This subject encompasses different perspectives, which in the end, are all interconnected. Coordination may be required in different time-steps (e.g., long-term planning, real-time operation), as well as on different layers of power systems functioning (markets, operations, data management, etc).

On the different time-steps that may require enhanced coordination, Table 2.2 foresees some of the situations in which coordination will be required.

Ex-ante		Real time	Ex-post
Long-term	Close to real time		
• Planning grid expansion • Long-term procurement (e.g., curtailment contracts)	• Procurement of flexibility • Technical validation and operation planning (dispatching) • Forecasting	• Real-time grid management • Activation of flexibility	• Metering data sharing • Settlement

Table 2.2: Different coordination needs for different timesteps.

As power flows are expected to become bidirectional, network planning will have to be done in a coordinated way. On the long-term, non-firm capacity contracts will have to be coordinated, so that DSOs and TSOs know what each one can still procure from each DER and subsequently consider in the grid development decisions.

Close to real-time, several procedures will require coordination, such as energy procurement in spot-markets (avoiding potential grid congestions), as well as the operational planning and possibly forecasting. Another example is the technical validation, which is carried out by TSOs in coordination with market operators or power exchanges today. However, as more DERs are integrated into the system, DSOs may also need to play a role in this technical validation of market results.

In real-time, the grid management and the activation of previously procured flexibility will also have to be done in a coordinated manner. As of today, TSOs are the sole responsible for activating reserves, either automatically or manually. As DER start to provide more AS to TSOs, DSOs may have to perform an ex-ante validation of bids. Finally, ex-post financial settlements may require coordination as well.

The achievement of enhanced coordination will, on one hand, enable TSOs and DSOs to improve planning and allow for flexibility procurement for more economically efficient grid management and, on the other hand, improve the resilience of the system. The coordinated system operators will have improved means to cope with emergency situations (e.g., providing a more efficient restoration of the system after a blackout).

2.3 Missing Elements for TSO-DSO Coordination in Balancing and Local Congestion Management

Coordination will be necessary for multiple situations from the planning to the operation of power systems, at different time-steps. Hereafter, this section identifies what the most urgent situations in which coordination will be required may be, and what the necessary elements for this coordination to happen are. Herein, the focus is placed exclusively on the coordination for the operation of the power sector. Although coordination for planning is equally important, it presents challenges of a different nature, and therefore it is not addressed in this chapter.

In order to help with this identification, the classification of primary electricity services developed by Pérez-Arriaga et al. (2016) is used. Considering the integration of variable renewable generation and DER, the authors identify a set of primary electricity services that must exist for the system to function properly. These services are divided into two groups, namely energy-related services and network-related services. Table 2.3 presents the ten primary electricity services. It is worth noticing that flexibility is not a service per se, but a feature that enables an agent to provide certain energy and network-related services.

Villar et al. (2018) define flexibility as being the capacity for "modifying generation and/or consumption patterns in reaction to an external signal." Hans de Heer and Willem van den Reek (2018) complement this definition by stating that "this ability changing the pattern can be deployed either directly, by an external signal, or individually as a response to a financial incentive such as energy prices and tariffs." Flexibility, although it is not a service in itself, is the main characteristic that enables DER to provide services to both TSOs and DSOs.

As mentioned previously, DSOs are expected to have an active role in grid management, procuring services from local resources. In fact, DSOs will be able to use DER for most of the network-related services identified in Table 2.3, including voltage control, local network constraint man-

Energy-related services	Network-related services
• Electric energy • Primary operating reserves • Secondary and tertiary operating reserves • Firm capacity • Black-start capability	• Network connection • Voltage control • Power quality • Network constraint management • Energy loss reduction

Table 2.3: Classification of primary electricity services: energy and network services. Source: based on Pérez-Arriaga et al. (2016).

agement, and loss reduction. On the other hand, TSOs are also procuring balancing services [5] from resources connected to the distribution grid, as mentioned above. Therefore, the first operational situation that will require coordination is when balancing is procured by the TSO using DER flexibility, and the DSO also procures DER flexibility for local congestion management. This situation calls for coordination as the activation of one product can impact the possibility of activation of the other one. Coordination must ensure that both services (balancing and local congestion management) can be offered by flexibility providers but only used once in a timeframe. Additionally, when providing balancing services to the TSO, flexibility activation should not create local congestion problems or by activating a resource for congestion management, the effect on the system balancing has to be properly accounted.

In order for balancing and local congestion management coordination to work, several regulatory and operational aspects are still under development and being explored by the academic literature and pilot projects. Four necessary elements for balancing and local congestion management have been identified: DER flexibility integration, coordination schemes for flexibility procurement and activation, transmission and distribution optimisation techniques and data exchange.

DER flexibility integration (especially from small DER) into energy and service markets is the first step towards TSOs and DSOs being able to procure DER for grid management purposes. Following flexibility integration, coordination schemes are necessary to set the market and operational rules on how TSOs and DSOs will procure and activate services in the most efficient way possible. For these coordination schemes to be designed and tested, optimisation may also be required, raising the problem of how to properly model transmission and distribution networks for dispatch analysis. Finally, data exchange is also required as grid operators will have to exchange data on procurement, system operation and ex-post metering.

The integration of DER flexibility is at the centre of the transmission-distribution coordination discussion. With the increased penetration of different types of DER, both distribution and transmission system operators may be interested in using the flexibility from these resources. This is true to novel DERs connected to the MV and LV, but also the ones connected HV levels of the DSO. As discussed previously, most DSOs in Europe operate the HV. In most cases, this will be the interfacing network with the TSO. Also, DERs are expected to have a higher impact on the TSO operations when connected at the HV of the DSO.

[5] Balancing services can be undertood as primary, secondary and tertiary operating reserves, according to the nomenclature presented in Table 2.3.

The first step towards having TSOs and DSOs procuring DER flexibility for balancing and local congestion management respectively is to allow the DER flexibility to participate in energy and network-related markets. Three main barriers to the participation of DER flexibility in energy and network-related service markets have been identified, as illustrated in Figure 2.4. Barrier 1 is related to the possibility for DER flexibility to be used by an independent aggregator[6], as independent aggregation is still very limited and even forbidden in some countries. Besides that, certain types of aggregation are still not allowed in some countries/markets either (e.g., aggregation of demand together with generation may not be allowed). Barrier 2 is related to the possible conflicts between Balance Responsible Parties (BRPs) and aggregators, that can make independent aggregation not an interesting business model. Barrier 3 refers to the rules for accessing flexibility markets and rules for service provision. That is the case mostly for balancing markets, such as minimum bid sizes.

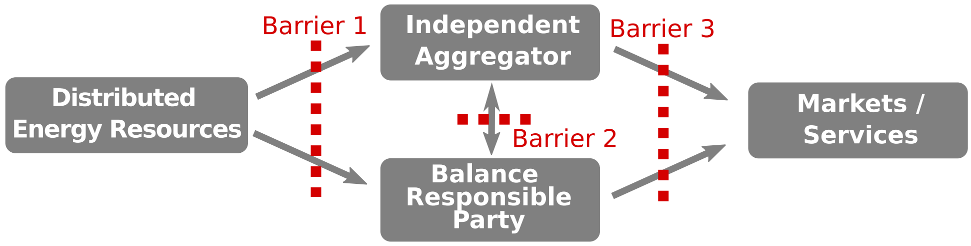

Figure 2.4: Barriers for DER Flexibility integration in energy and network-related service markets.

Aggregation is a key enabler for DER flexibility integration in energy and network-related markets. Balancing markets, for instance, involve complex procurement auction mechanisms and can be concentrated, dominated by a few large players (Heim and Götz, 2013; Ocker et al., 2018). These characteristics may represent a barrier to entry for DER, marked by a relatively small size compared to other players, and whose main business model is not the participation in power markets. Therefore, the aggregator can be the bridge between the DER potential and energy and network services. An aggregator is an agent that pools flexibility and offers it into different markets. Aggregation can be done by an existing agent such as a retailer, or independently.

The retailer may have an incentive to use aggregation to reduce imbalance costs. In Europe, every retailer is also a BRP, or part of one. A BRP is responsible for keeping its load/generation profile equal to or close to the scheduled one. Otherwise, the BRP has to bear the corresponding share of imbalance costs. Therefore, BRPs may use their own clients' flexibility to reduce imbalances instead of trading positions in the intraday markets or being penalized with imbalance costs. Biegel et al. (2012), for example, model how BRP may use flexibility from consumers to avoid high imbalance costs.

However, some argue that the independent aggregator is the one expected to trade the flexibility from different types of DER in energy and network service markets. In fact, the concept of the

[6] An independent aggregator is an aggregator that is not affiliated to a supplier or any other market participant.

Virtual Power Plant (VPP) expresses this possibility of service provision for both the TSO and the DSO (Zhang et al., 2014).

The independent aggregator, however, still faces several barriers in Europe. The first one consists of the fact that the independent aggregation is still not allowed in many countries. In those countries in which they are allowed, such as Austria and Germany, their participation in energy markets has been so far limited (Poplavskaya and de Vries, 2018). This can be in part attributed to the complicated relationship between independent aggregator, retailers, and BRPs (Poplavskaya and de Vries, 2018; Sweco et al., 2015).

Let us imagine a consumer that has a contract with an independent aggregator and a retailer (being two different companies). The retailer (that is also a BRP) schedules the consumption of this customer and is responsible for keeping the schedule[7]. The independent aggregator, however, uses the customers' flexibility to provide balancing services for the TSO. This ultimately generates an imbalance for the retailer that, in the absence of the corresponding compensation mechanisms, will now have to bear with the imbalance cost and may request compensation from the aggregator.

According to the CEP, independent aggregators should not be required to seek the authorisation of their customers' supplier or any other market participant in order to sign a contract with a final customer (European Commission, 2019a). However, they may have to provide financial compensation, exceptionally, if they impose imbalance costs, as exemplified in the above-mentioned example. Financial compensation is allowed "if those market participants or balance responsible parties are directly affected by demand response activation" (European Commission, 2019a). This situation affects the incentives for independent aggregators. Faced with possible compensations, with no way of predicting them, their business model may become too risky. Therefore, an important barrier is still on how to foster the development of independent aggregation without creating problems for the system and other market players, while ensuring an overall benefit for the system.

Finally, another barrier that may exist for DER flexibility to be offered in balancing markets is the rules for participation. MacDonald et al. (2012) compile the rules and characteristics of balancing in the US and shows that for several of them, there is still a minimum size requirement that may prevent small DER from offering their flexibility. In the US, minimum sizes for participation in reserves vary from 0.1 to 1 MW, the latter being the most common. Sweco et al. (2015) also argue that, although the threshold at 0.1 MW might not be a barrier, especially when resources are aggregated, some balancing markets have a higher minimum bid size. Only recently, with the proposal for a Network Code for Demand Response, the minimum bid size is expected to be lowered to 0.1 MW. However, derogation is possible. As the proposal explains, "ENTSO-E considers the integration of smaller resources in balancing processes is more efficient and effective through aggregation. There is an understanding that lowering minimum bid below 1 MW size has very low added value in terms of improving market access requirements and may create an unnecessary burdensome process, while at the same time making it more difficult the monitoring of service performance" (EU DSO Entity and ENTSO-E, 2023).

[7] Retail scheduling is done on a portfolio basis. However, for illustrative purposes, the schedule of one single consumer has been considered.

2.3.1 Coordination Schemes for Flexibility Procurement

Once the DERs start actively participating in TSO and DSO markets, the next challenge is how to organize clearing and dispatch so both the SOs can procure and activate resources efficiently without creating congestions to each other. These specific market designs for network services involving both the TSO and the DSO have been called coordination schemes by the recent literature (Anthony Papavasiliou and Mezghani, 2018; Gerard et al., 2016; Migliavacca et al., 2017).

Coordination schemes can be defined as market designs, operational processes and information exchanges involving both TSO and DSO for the procurement and activation of energy and network-related services. This topic has started to be explored in recent years, and it is still at a conceptual level. A complete framework covering all aspects of market design, operational processes and information exchanges for current energy and network-related services has not been developed yet. The state-of-the-art on this topic focuses rather on a high-level approach defining market designs for "central markets" at the TSO level and "local markets" at the DSO level (Gerard et al., 2016). At this stage, the particularities of each service are not taken into account completely. The coordination schemes are rather focused on setting responsibilities for TSOs and DSOs in particular market design, and how they would interact under each scheme.

The main questions that the coordination schemes try to answer are: who operates energy and network-related service marketplace? Who has the priority over resources connected at both transmission and distribution levels? How is the technical prequalification performed? And in the case of separated marketplaces, how are the remaining resources passed from one SO to the other considering different market sequences?

To start answering these questions, the current state of coordination between TSO and DSO may be considered. Currently, only the TSO runs service markets and even resources connected at the distribution level bid into the market organized by the TSO. The DSO, as of today, does not have organized markets for local services such as local congestion management (with a few exceptions, as shown in Valarezo et al. (2021)). This situation, namely the TSO responsible for all network-related service markets and also responsible for the activation of resources at both transmission and distribution, is also considered a possibility for the future. Several authors consider this as one coordination scheme (Gerard et al., 2018; Kristov et al., 2016; Paul De Martini et al., 2015). This type of coordination scheme, however, leaves limited opportunities for the DSO to procure local services.

Another popular type of coordination scheme is the one in which the TSO runs a Central Market (CM), and the DSO runs a Local Market (LM). In this case, the TSO would run a central market according to its own need (e.g. balancing, congestions), and the DSO would also procure DER flexibility in line with its own needs (e.g. overloads, voltage issues). The central question for this type of scheme is how (and if) the TSO could access the resources at the distribution level.

The research on CSs have gained considerable attention in the recent years. Large European Research and Development project have proposed, studied and demonstrated several possibilities in terms of CS. The SmartNet project, for instance, has proposed five different CS, as listed below (Gerard et al., 2018).

- Centralised AS market model: a single flexibility market for operated by the TSO. The TSO procures flexibility from the DERs directly and the DSO has a limited role.

- Local AS market model: In this CS, the DSO runs a LM in order to solve their own needs. Unused bids are then forwarded to the TSO market. This CS is also known as the Multi-Level CS in other works (Gürses-Tran et al., 2021).
- Shared Balancing Responsibility: In this CS, both the TSO and DSO are responsible for balancing their own grids, committing to an initial schedule at the interface (e.g. results from DA markets).
- Common TSO-DSO market model: similarly to the Centralised CS, in this Common CS only one market exists. The difference is in the fact that both TSO and DSO are the buyers, and jointly operate the market. No upfront priority to the TSO or DSO exists.
- Integrated Flexibility market model: This CS extends the previous one to include other parties as buyers to the single flexibility market. In this case, an independent market operator is necessary to ensure neutrality.

This five CSs were later adapted and expanded by the CoordiNet project (Delnooz et al., 2019), leading to market model framework that classifies the different CSs according to the following questions:

- Where is the system need (central vs. local)?
- Who is the primary flexibility buyer?
- How many flexibility markets there are?
- Does the TSO have access to DER flexibility?

Based on this framework, seven different Market Models (MMs) are defined, as illustrated in Figure 2.5. The MMs are not all CSs as some do not involve the TSO (e.g. distributed, local). However, the Common, the Multi-level and the Fragmented CSs are among typical CSs.

The literature around the different CSs has explored the advantages and disadvantages of the proposed schemes. From a purely techo-economic perspective, Marques et al. (2023) proves that the Common CS will always lead to the least cost of flexibility procurement. The fact that only one optimisation problem is solved taking into account all variables at the same time leads to the most efficient solution. Nevertheless, from an implementation point of view, the Common CS may present additional challenges with respect to other CSs.

The Common CS usually assumes that only one Market Operator (MO) exists, which has visibility over the flexibility market and the networks at the same time (both transmission and distribution). This MO could be an independent MO or one of the SOs, usually the TSO (Gerard et al., 2016). In this context, the SOs which are not the MO would need to transfer or exchange network information. This may represent both a challenge in terms of ICT and data-privacy.

On the one hand, centralising both transmission and distribution grid information for Optimal Power Flow (OPF)-type of Common CS can be very complex, especially if the MV and LV are to be represented. Li et al. (2020) builds a highly detailed synthetic transmission-distribution network located in central Texas, going from 120 V to 230 kV voltage levels. The resulting network

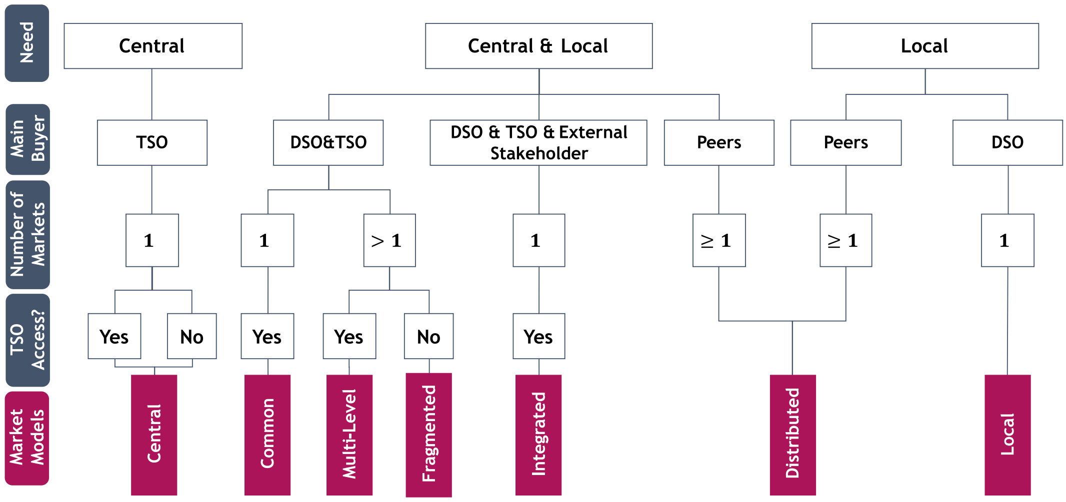

Figure 2.5: Coordination Schemes. Source: Gürses-Tran et al. (2021).

includes 307 thousand customers and 1.6 million electric nodes. Li et al. (2020) also acknowledges that very few tools are well suited for solving power flows on 1 million node or more networks. In the European context, in which one TSO usually operates the transmission of a whole country, having one single OPF including all distribution and transmission voltage levels seems unfeasible at the moment. This is also the case considering that simplified OPF models, such as the DC OPF, are not fit for MV or LV (Purchala et al., 2005).

On the other hand, data privacy is also a major concern for SOs, as both TSO and DSO network and customer data is partially or totally private. In the Common CS operated by the TSO or a third-party (e.g. an independent market operator), network and customer's data would have to be provided by the other SOs.

In this context, several authors have tried to enable the implementation of a Common CS with reduced information exchange needs. The most common technique proposed is the use of decomposition algorithms. The decomposition algorithm allows for the separation of the optimisation problem into two or more problems, which are solved separately with the exchange of few coupling variables in an iterative fashion, until convergence towards optimality is achieved. The Alternating Direction Method of Multipliers (ADMM) has been used by several authors to implement the Common TSO-DSO decomposition (Chen et al., 2021b; Ivanko et al., 2022; Jiang et al., 2022; Marques et al., 2023). Although the use of a distributed OPF could overcome the data privacy challenge, other data-exchange related issues may still exist for the implementation of the Common CS. Rodriguez Perez et al. (2023) conducted an analysis of the different ICT architectures for TSO-DSO data exchange in Europe and concluded that the implementation of the decentralised Common TSO-DSO market model is considered to be the most challenging from an ICT point of view, requiring seamless real-time synchronisation of different market platforms or processes.

The alternative to overcome data privacy and some ICT issues is the adoption of a sequential or hierarchical CS. Therefore, the Multi-level CS would allow for the TSO and the DSO to access and use distributed flexibility for both local and central needs, such as the Common CS.

A typical implementation of the Multi-level CS is known as the "Flexibility Region" or "Feasibility Region". This line of research consists of calculating the available flexibility to the TSO in an aggregated form. Therefore, the DSO would compute the region at the P/Q plane for the interfacing substation in which the TSO could request the DSO to deviate with respect to the original expected setpoint. Three main methods have been used for the flexibility region calculation, namely, Geometric, Random Sampling, and optimisation-Based (Papazoglou and Biskas, 2022). The first method, less used in the literature, consists of calculating the geometric addition of the P/Q flexibility regions of all FSPs available. The downsides of this method are the high computational cost and, especially, that is does not take into account the distribution network constraints. The second method, the Random Sampling, consists of (i) selecting a large number of random FSP setpoints, (ii) computing the power flow for each random setpoint and (iii) including the setpoint to the flexibility cloud if the power flow is feasible. The flexibility region for the Random Sampling method is then the frontier of the flexibility cloud of feasible setpoints. Scenarios can be generated by Monte Carlos analysis, as in Ageeva et al. (2019). The optimisation-Based method consists of optimising the setpoints for the different FSPs with respect to the expected P/Q position at the interfacing substation. The optimisation is carried out for different vertexes of the flexibility region, or angles around the initial setpoint. The Flexibility Operating Region (FOR) methods, however, could face some regulatory barrier, as the DSO aggregates bids and may act directly on the TSO market. Also, the FOR makes the DER participation in the TSO market less transparent, which may also be seen as a barrier from the CEP's perspective.

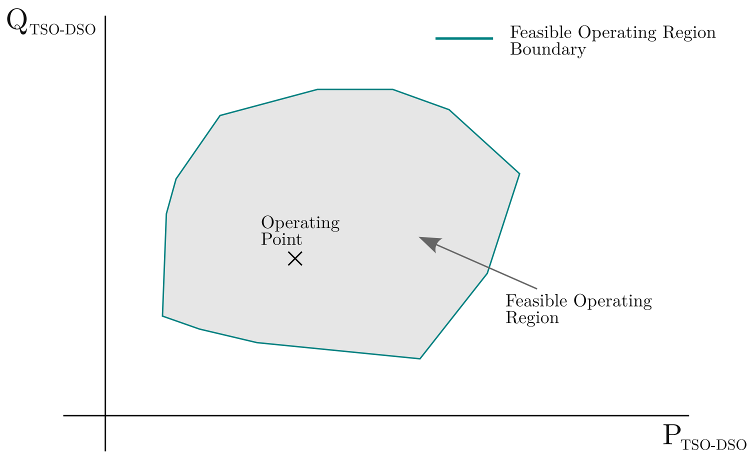

Figure 2.6: Example of a Flexibility Operating Region (FOR). Source: Papazoglou and Biskas (2022).

An alternative to the calculation of the DSO-aggregated flexibility region is the individual bid forwarding from the Local Flexibility Market (LFM) to the TSO-operated market(s). This assumes a sequential multi-level CS, in which first the DSO clears the LFM and then the TSO clears the central congestion management and/or balancing markets. Unused bids from the LFM are forwarded to the TSO as long as they do not introduce new congestions to the DSO.

When flexibility markets are optimised in a sequence, inefficiencies are introduced. Firstly, counter-activation may take place, meaning that one resource is activated by the DSO in on direction, and later by the TSO in the opposite direction (Lind et al., 2021c). The economic inefficiencies may also be the result of poor cost allocation between SOs. Assuming that the local flexibility market is cleared first, and that no restriction exists on the power flow over the interface, the clearing of the local flexibility market may lead to imbalances in the systems, to be solved by the TSO in later markets.

Current LFM initiatives vary in the products and services they procure. The platform GOPACS, for instance, is a joint initiative by the TSO and DSO in The Netherlands that uses the existing intraday market to tackle congestions at both transmission and distribution (Valarezo et al., 2021). The PICLO platform, implemented in many regions of the UK, on the other hand, functions as an independent LFM in which the DSO procures capacity and/or energy in the direction needed to solve congestions. In other words, if a transformer is congested, the DSO might procure upward[8] flexibility downstream of the transformer to solve the congestion. Following this procurement, the TSO is only informed about the activation (Schittekatte and Meeus, 2020).

The functioning of the PICLO platform may lead to an important source of inefficiencies in hierarchical/sequential CSs such as the multi-level. When an FSP is activated in one direction to solve a congestion at the distribution level, the same energy should be activated in the opposite direction somewhere else in the system to maintain the demand-generation balance, or, in other words, complete the redispatch process. Independent of the balance responsibility of the FSPs, this split in the redispatch leads to economic inefficiencies (high cost of flexibility procurement) and myopic cost allocation (as the TSO pays to complete the redispatch of the DSO).

Several proposals have been made in order to solve both the cost allocation problem as well as the cost efficiency of the multi-level CS. Vagropoulos et al. (2022) propose that the DSO could be a BRP, although this proposal could be contrary to the regulatory principle that DSOs should be neutral market facilitators and not market participants. Another proposal to ensure proper cost allocation is to "fix" the power flow at the interfacing substation. This is, in fact, the definition of the Fragmented CS, in which SOs can only use resources at their grids and must respect the scheduled power flow the interfacing substation (e.g. from the DA market) (Gürses-Tran et al., 2021). In this case, if flexibility markets are used, SOs will have to procure the flexibility required to solve their network problems (e.g. upward flexibility to solve congestions), but also flexibility in the opposite direction to maintain the initial power flow at the substation, and therefore the generation-demand balance (Marques et al., 2023). These two proposals exemplify how to introduce appropriate cost allocation to the multi-level CS. However, these proposals may not necessarily improve the cost efficiency of the CS.

Marques et al. (2023) argue that the economic efficiency of the Multi-level CS can be improved if the variation in the power flow over the interfacing substation is priced properly. In fact, it is proven that, if the variation over the power flow is priced properly, the Multi-level and the Fragmented CSs can lead to the same result as the Common CS. In order to compute the interface power flow price, first the authors compute a "virtual" Common CS, and then the Multi-level/Fragmented. Although illustrative, this method is not practical. Therefore, the same authors propose the implementation of a bilevel model with decomposition of the optimisation problem. This allows for the practical implementation of the Multi-level CS in which both SO have independent markets. Nevertheless, this leads to the same challenges as the distributed Common CS

[8]Upward flexibility is here understood as the increase of generation or, equivalently the reduction in consumption. Downward flexibility being the opposite.

implementation, namely, (i) both markets have to be cleared simultaneously (so the convergence of prices at the interface can be achieved), and (ii) the ICT challenges are higher, as the near real-time information exchange has to take place.

Table 2.4 provides a summary of the advantages and the disadvantages identified for each CS. From a market design perspective, it is also important to note that DERs would have one market entry point to all three CSs analysed, meaning that only one flexibility bid is offered. In the case of the Common CS, this bid serves both the TSO and DSO, while on the Fragmented, only the SO to which the flexibility provider is connected to. In the case of the Multi-level, the bid is first submitted to the DSO and, if unused in the LFM, forwarded to the TSO. The bid forwarding procedure, however, requires bid standardisation, so that they can be used by both DSO and TSO. Moreover, it also requires the DSO to assess the technical feasibility of the bids, should they be activated by the TSO. This ensures that the activation of the forwarded bids does not lead to new network issues for the DSO.

CS / Variations		Description	Simultaneous / sequential markets	Advantages	Disadvantages
Common	Centralized	A single MO clears flexibility needs for both DSOs and TSOs. In the centralized variation, the market clearing algorithm is run completely by the MO.	Simultaneous	Leads to the least cost of procurement	Large market clearing problem; Network information sharing.
	Distributed	Still only one MO solves problems for TSOs and DSOs. However, the algorithm is run iteratively from the SO premises, so that no network information has to be transferred to the MO.		Leads to the least cost of procurement; No network information sharing.	Complex near real-time information exchange.
Multi-level		A market sequence is established. Usually, the DSO first runs a LFM. Unused bids are sent over to the TSO, which runs their markets (balancing, congestion management).	Sequential	No need for sharing network data.	Not only unused bids have to be forwarded, but also restriction on what the TSO cannot activate in order not to create problems. The feasibility region field of research proposes a solution. However, the DSO would have to aggregate bids, possibly creating a regulatory conflict; Market fragmentation will lead to higher cost of flexibility procurement when compared to the Common CS.
Fragmented		TSOs and DSOs can only use units connected to their grids. In addition, the power flow over the interfacing substation must be maintained according to what was scheduled (e.g. Day-ahead results).	Independent	No information sharing.	Higher losses of efficiency, as the SOs are limited to resources connected at their grids, and they have to complete the redispatch using the resources connected at their grids only.

Table 2.4: Advantages and disadvantages of most relevant CSs.

2.3.2 TSO-DSO Data Exchange

Data exchange will play an important role in TSO-DSO coordination from the pre-qualification process to the final settlement. It involves platforms, protocols, timesteps, and data structure to be exchanged between TSO and DSO for operational purposes. The CEP states that TSOs and DSOs "shall exchange all necessary information and data regarding, the performance of generation assets and demand-side response, the daily operation of their networks and the long-term planning of network investments, with the view to ensure the cost-efficient, secure and reliable development and operation of their networks" (European Commission, 2017c)[9].

For congestion management, the report highlights the need for increased observability between grids. The System Operation Guideline (SOGL) devotes Title 2 (Articles 41 to 53) to data exchange, including TSO-DSO data exchange (European Commission, 2017a). The guideline, however, is focused on the need of TSO to receive data from the DSO. The latter should send both structural data about the distribution grid (Article 43) and real-time data (Article 44). The contrary, however, is not true. According to the SOGL, TSOs are not mandated to provide the DSO with structural or real-time data.

Regarding balancing, the report recommends that "DSOs should at any time be able to assess the impact of the activation of balancing services on their grid at different timeframes (e. g. within the prequalification process, balancing market gate closure time to real time)" (CEDEC et al., 2016). Therefore, the DSO should be informed in the case of DER flexibility activation by the TSO for balancing purposes in order to avoid harmful interference with the distribution grid operation.

Finally, it is worth mentioning that proper data exchange will be only possible if the required network infrastructure is in place. This includes not only the appropriate visibility of resources connected to the distribution networks, but also communication systems between TSO and DSOs, and possible platforms that help on coordinating procedures. Metering and data exchange will also be necessary for the settlement process of the services provided to DSOs and TSO.

2.3.3 Transmission-Distribution optimisation Models

Optimisation is a key tool for researching coordination schemes and for actual market clearing. Optimising transmission-distribution networks for solving balancing or local congestion management imposes several technical challenges. The two main barriers are the size of the optimisation problem and the challenge of optimising Alternating Current (AC) power flows.

A transmission-distribution power flow problem is expected to be a lot larger than is used currently for transmission networks. While a transmission grid model may have a few thousand nodes, a distribution grid can have several million for a country or a region, as shown in Table 2.1. Additionally, the heterogeneous characteristics of the distribution network can also be a problem for future algorithms. This may be an important barrier when computational time matters for a certain application. That could be the case for clearing balancing bids, for example. Assuming that DER at the LV level can provide a service such as secondary regulation that would have to be fully activated within 15 minutes, the clearing algorithm would have very limited time to reach a solution. As an example, the MARI platform proposed by ENTSO-E would have to find a solu-

[9] Article 53 (1)

tion for manual Frequency Restoration Reserve (mFRR) provision within 1 minute (ENTSO-E, 2017).

Optimising the dispatch of generating units in a transmission network has been fairly simple to compute and extensively done. At the high voltage transmission level, it is common to use the approximation that removes reactive power from the calculation or a Direct Current (DC) OPF for unit commitment and economic dispatch. The simplifications imposed by such methods, although not precise, allow for a quick, intuitive and reliable estimation of power flows. However, for the lower voltage levels, these are not good assumptions essentially due to the comparatively low X/R ratio[10] of MV and LV lines. Therefore, the use of an AC OPF is necessary.

The AC OPF is a non-convex problem, and therefore nonlinear solvers are not able to find a global solution to the problem (Yuan and Hesamzadeh, 2017). Therefore, some relaxation and approximation techniques are being used in the literature in order to deal with this challenge.

Considering that the AC OPF, although offering the most precise results, cannot be easily optimised, both convex relaxation and linear approximation can be used to manage computational tractability. However, these relaxations and approximations in the different classes of optimisation problems come at a cost in terms of features and accuracy. Geth et al. (2017) classify the hierarchy between the different types of optimisation classes:

$$LP \subset QP \subset SOCP \subset SDP \subset NCQCP \subset NLP^{11} \tag{2.1}$$

Being the AC OPF an NLP, each step given from the right to the left will make the optimisation problem easier to solve, but less accurate. The example of a strong simplification of the AC OPF is the DC OPF, an LP problem, easy to solve, but in which reactive power flow is neglected.

The current state-of-the-art in AC OPF relaxation favours two main techniques. On the one hand, SOCP is used by several authors (Anthony Papavasiliou and Mezghani, 2018; Baradar and Hesamzadeh, 2014; Baradar and Hesamzadeh, 2015; Caramanis et al., 2016; Huang, 2015). On the other hand, SDP has been equally important for research (Bai et al., 2008; Jubril et al., 2014; Lavaei and Low, 2012). Nevertheless, despite its drawbacks, the DC power flow has also been used for modelling distribution networks sometimes, as in the work done by (Manshadi and Khodayar, 2016).

These techniques are already being used to test quantitatively the coordination schemes previously described. Anthony Papavasiliou and Mezghani (2018) model the coordination schemes proposed by Gerard et al. (2018) using SOCP. Considering the activation of reserves for balancing real-time deviations, the authors use SOCP to perform an economic evaluation of the different coordination schemes.

Regarding the fitness of the two main relaxation techniques, SDP may be considered stronger than SOCP but requires heavier computational resources, as advocated by Bingane et al. (2018). Therefore, SDP may be more appropriate for test cases for research purposes, while SOCP may be more reliable for real-size networks. Indeed, state-of-the-art solution methods for SOCP problems are faster and more scalable than SDP counterparts (Geth et al., 2017).

[10] Resistance (R) and Reactance (X), respectively

[11] Linear Programming (LP), Quadratic Programming (QP), Second-Order Cone Programming (SOCP), Semidefinite Programming (SDP), Nonconvex Quadratically Constrained Programming (NCQCP), Nonlinear Programming (NLP).

It is worth noticing that for a problem involving the optimisation of both a transmission and a distribution network, different techniques may be used for the different networks. That is the case for Geth et al. (2017) and Anthony Papavasiliou and Mezghani (2018), that use DC OPF for meshed transmission grids and SOCP for the distribution grids.

Another alternative that became popular in recent years is the use a linearised algorithm LinDistFlow for the distribution grid (Beckstedde et al., 2023; Marques et al., 2023). The LinDistFlow is the lossless variation of the DistFlow algorithm first introduced by Baran and Wu (1989). This method allows for a linearisation of the power flow equations while still providing the computation of nodal voltage magnitudes and reactive power flows. The drawback of this method is the limitation of usage to radial networks only. This may not be a big limitation in countries where the DSO operates up to the MV only. This and the LV level are usually operated radially, as shown in Table 2.1. However, as also shown above, most countries in the EU have DSOs also operating the HV, which creates a meshed-to-meshed topology for the TSO-DSO coordination.

2.4 Conclusions

This chapter has presented a broad review of transmission and distribution coordination in power systems. The ongoing changes taking place at different segments of the power supply chain call for greater TSO-DSO coordination. This coordination will be necessary for different time-steps, and for both planning and operation.

The chapter specifically focused on a key operational aspect of TSO-DSO coordination, i.e. on the situation in which the TSO procures balancing services from small DER flexibility and the DSO procures flexibility for local congestion management. Based on the review carried out, this is deemed the most critical situation, requiring closer coordination between both types of grid operators in the short and medium term. For this particular case, four missing elements enabling such coordination have been identified: (i) the DER flexibility integration in balancing and local congestion management markets, (ii) coordination schemes between TSO and DSO for the procurement of flexibility, (iii) transmission-distribution optimisation models, and (iv) data management and exchange.

Firstly, small DER flexibility still faces barriers to enter and participate in system service markets such as balancing, mainly due to uncertainties surrounding the activity of the independent aggregator, and the misalignment of incentives for different market players (e.g. BRPs and independent aggregators). In connection to that, DSO flexibility markets are still incipient.

Secondly, coordination schemes, although already researched, still present important gaps. It has been proven that the Common CS is the most efficient one from an economic perspective, leading to the least cost of flexibility procurement. However, the implementation of the Common CS is challenging from a data privacy perspective, as SOs would have to share network and customers' data. To overcome this problem, authors have proposed distributed methods in other to split the optimisation problem and solve it in an iterative way. Although this solution may overcome the data privacy barriers, it still presents the data-exchange difficulties, as near to real-time data has to be exchanged. Considering the difficult implementation of the Common CS, sequential or hierarchical CSs have also been proposed. Several authors have investigated the calculation of an aggregated flexibility region at the TSO-DSO interface. This proposal may allow for a combined TSO-DSO access to distributed resources. However, it belongs to the DSO the task to aggregate flexibility bids and communicate them to the TSO. This could be conflicting to the principles of a market neutral DSO. Moreover, extensive research has been done on the Multi-level CSs, in which the DSO forwards unused bids to the TSO markets. In principle, such sequential markets may introduce cost allocation and overall economic inefficiencies. One proposal to solve both is to correctly price the variation on the expected interface power flow. A practical way to achieve this goal is to have a decomposed model in which both TSO and DSO solve their markets in an iterative way. This, however, may lead to the same challenges as the distributed Common CS in terms of data-exchange challenges. Therefore, research is still needed in order to identify efficient and yet implementable CSs.

Thirdly, novel optimisation and modelling techniques are still needed if the goal is to have large scale market models that also represent the network in detail for a country or region, especially if the markets involves the use of OPF and the inclusion of MV and LV levels. In addition, a need for studies considering a meshed-to-meshed topology also exists, as most of the literature considers meshed-to-radial synthetic networks.

Finally, TSO-DSO data exchange mechanisms are still immature and barriers can be specifically identified for balancing and local congestion management, mainly due to the lack of data being sent by the TSO to the DSO. In this regard, development is required in terms of responsibility allocation, data privacy management, or infrastructure requirements (platforms and communications).

3 Modelling TSO-DSO Coordination Schemes[1]

This chapter proposes models for assessing different Coordination Schemes (CSs) in the context of distributed flexibility procurement used for balancing and congestion management at distribution and transmission grids. The proposed models focus on the coordination between the TSO and the high voltage distribution levels, introducing the meshed-to-meshed topology with multiple TSO-DSO interface substations. The models are applied to two realistic case study, namely the Swedish and the Spanish case studies. One-year period case studies based on real data are conducted, which are then subject to different sensitivity analyses.

3.1 Introduction

As shown in Chapter 2, the body of literature analyzing the techno-economic properties of CSs has focused on the theoretical development of CS algorithms and their testing on stylized or test case networks. Another characteristic of these works is the generalisation of a meshed transmission grid and a radial distribution grid (Anthony Papavasiliou and Mezghani, 2018; Le Cadre et al., 2019; Sanjab et al., 2022; Yuan and Hesamzadeh, 2017). On the European TSOs-DSOs landscape, however, these characteristics are not always observed. As shown in chapter 2, in most European countries, the DSO also operate the HV level (Eurelectric, 2020). For this reason, in this chapter we focus on the coordination that may take place between the transmission grid and

[1]This chapter is based on the following journal paper and technical report:
Journal paper:

- L. Lind, R. Cossent, and P. Frías (2023). "Evaluation of TSO–DSO Coordination Schemes for Meshed-to-Meshed Configurations: Lessons Learned from a Realistic Swedish Case Study". *Sustainable Energy, Grids and Networks* 35, p. 101125. ISSN: 23524677. DOI: 10.1016/j.segan.2023.101125

Technical report:

- R. Cossent, L. Lind, O. Valarezo, M. Troncia, and J. P. Chaves (2022). *CoordiNet D6.4 - Scalability and Replicability Analysis of the Market Platform and Standardized Products*. Technical report

HV grid of the distribution network, as this analysis is still not explored in the literature. The main difference from the MV and LV networks is their typically meshed configuration.

In this context, TSOs-DSOs coordination is also expected to happen in meshed-to-meshed topologies. One important difference in the modelling of CSs, in this case, is the existence of multiple TSOs-DSOs interfaces. The shift from a meshed-to-radial to a meshed-to-meshed topology implies new challenges for the TSO and DSO. When only one TSOs-DSOs interface exists, the interface power flow can be more easily forecasted according to market actions taken by the SOs in the different coordination schemes. When multiple interfaces exist, however, the interface power flow forecast becomes less straightforward in sequential coordination schemes, potentially introducing losses of efficiency depending on the information shared between TSO and DSO. In this chapter, we adapt the optimisation algorithm to allow for both TSO and DSO to forecast the power flow in each substation in decoupled CSs.

Equally missing in the literature is the assessment of TSOs-DSOs coordination schemes in a realistic case study. In this chapter, we propose an assessment for Sweden and Spain considering a representation of the transmission grid together with a representation of selected subtransmission grids in the different parts of the two countries. In Sweden, the 70 kV subtransmission grid in Uppsala region is included. In Spain, 132 and 66 kV networks in the Albacete and Cádiz regions are included.

The study also comprises a period of one year. While existing research focuses on the assessment of a single critical hour up to one critical day, we propose the use of a yearly case study. Real data from the Swedish TSO Svenska kraftnät for the year 2020 is used together with the actual data from the distribution grid from the demonstration of the EU Horizon 2020 Research and Innovation project CoordiNet (Cossent et al., 2022). Similarly, real data from the Spanish TSO Red Eléctrica is used.

Also, a complete market sequence is used, including a DA market model that generates the congestion to be solved by flexibility markets. This chapter aims to provide a comprehensive TSOs-DSOs model, including different CSs focused on the TSO (EHV) and the HV DSO grids. This model is then applied to the Swedish power system considering real consumption and generation data for one year. Finally, several sensitivity and replicability scenarios are analyzed.

More specifically, the contributions of this chapter are summarized as follows:

1. The modelling of different CSs for the procurement of balancing and congestion management in meshed-meshed grids with multiple TSOs-DSOs interfaces. This implies the implementation of a novel formulation for the forecast of the power flow in each substation by the DSO and TSO in sequential CSs.

2. The application of different CSs to realistic systems and case studies, use of a realistic representations of Swedish and Spanish transmission and subtransmission grids, together with a yearly case study. Additionally, a complete market sequence is modelled (day-ahead followed by a congestion management market and a balancing market).

3. The testing of the behaviour of CSs for different scenarios of sensitivity and replicability.

The rest of this chapter is organized as follows: In section 3.2, the modelling of the different CSs is presented. Section 3.3 presents the Swedish case study, while section 3.4 presents the Spanish case study. Section 3.5 provides the interim conclusions of the chapter.

3.2 Modelling Coordination Schemes

In this chapter, a combined TSO-DSO model for the procurement of flexibility, including flexibility from DERs, is presented. This model aims to provide an assessment tool for different TSO-DSO coordination schemes, considering that both SOs may utilize resources connected to the distribution grid. Therefore, the model proposed is composed of three building blocks, namely, a wholesale energy market, a congestion management market, and a balancing market. We aim to model a complete market sequence so that costs and benefits can be assessed for realistic case studies. Therefore, it is necessary to model the DA wholesale energy market, as the results from this market will generate the need for redispatching in congestion management markets, for instance. Additionally, the model contains intertemporal constraints linking 24h periods. With the use of clustering techniques and representative days, yearly results can be obtained (as detailed in section 3.3).

The model proposed in this chapter aims to describe a generic European market sequence, as described in CEDEC et al. (2019) and Meeus (2020). This means that firstly, a DA wholesale energy market is operated without considering network constraints other than between bidding zones (limited by their Net Transfer Capacity (NTC)). The DA is followed by a congestion management market in which the system operator (TSO and DSO, depending on the CS) will check for the feasibility of the dispatch. In case of network violations, the SO solves them using congestion management markets. These markets act as corrective markets considering the results from the DA market, the offers from flexibility providers in the congestion management markets and the network limits and characteristics. These markets take place in between the DA and near real-time timesteps. Finally, near real-time, another type of 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. The red boxes in Figure 3.1 illustrate the market sequence considered. First, the DA market; second, the congestion management market; and third, the balancing market. In this chapter, congestion management and balancing markets are also referred to generically as flexibility markets.

In this chapter, we focus on the Coordination Schemes that allow both TSO and DSO to procure distributed flexibility, namely the Common and the bid-forwarding Multi-level CSs. One implementation of the Multi-level CS is the Flexibility Region coordination mechanism, which has recently gained attention (Papazoglou and Biskas, 2022). In this type of coordination, the DSO aggregates the distributed flexibility at the TSO-DSO interfacing substation using different methods, some of which do consider the network (e.g. Random Sampling and Optimisation-based methods) and therefore prevent TSO activations of distributed flexibility to cause congestions, acting as a bid prequalification. However, by acting as an aggregator of bids, the DSO could also act strategically, possibly deviating from its neutral market facilitator role defined by the European regulatory framework (European Commission, 2019a). Therefore, we model the Common CS, and the Multi-level CS, both in a joint balancing-congestion management configuration and a separate one, as introduced in Figure 3.2. These CSs both allow the TSO and DSO to procure distributed flexibility in a market design arrangement compatible with current European market sequence and regulatory framework.

The Common CS is defined as a single market in which both congestions and imbalances are solved (jointly or in sequence). It can be assumed that this market is run by a single entity (e.g. an

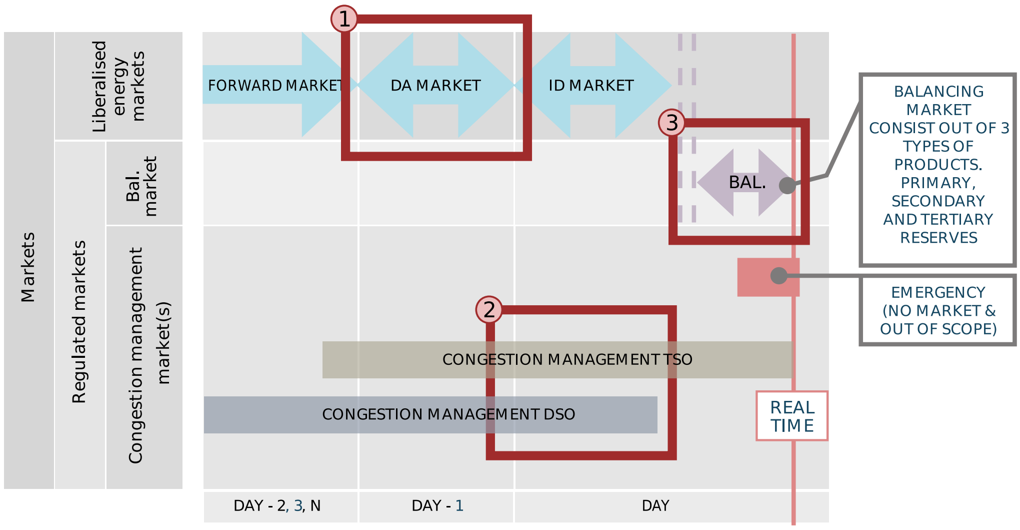

Figure 3.1: The sequence of electricity markets in Europe. Adapted from: CEDEC et al. (2019)

independent market operator or the TSO) and that both TSO and DSO procure flexibility in this market. The cost-sharing between TSO and DSO in this CS lies outside the scope of this chapter, being explored by Sanjab et al. (2022).

The Multi-level CS considers that firstly, the DSO is responsible for running a local congestion management market to solve congestions at the distribution grid, followed in time by the TSOs markets. In this sequence of markets, unused bids by the DSO are then passed on to the TSO market(s) if they do not create additional constraints.

For each CS, two variations exist, namely joint and separate. In the former, both balancing and congestions are solved jointly by the TSO, while on the latter, separate markets exist for the two services. Figure 3.2 presents an overview of the modelling approach described. Each blue box represents one market session. All market sessions are modelled as Mixed Integer Linear Programming (MILP) optimisation problems and implemented in General Algebraic Modeling System (GAMS). Their formulations are presented in the following subsections.

3.2.1 Day-Ahead Market

The day-ahead market is characterized by a clearing of the total demand $D_{i,h}$ in each hour and the merit order list of generation bids Bid_g. The day-ahead market is a short-term market in which consumers and producers attempt to individually maximize their benefits. However, under the assumption of perfect competition and inelastic demand, the problem is equivalent to a centrally managed power system operation with perfect information (Pérez-Arriaga, 2014). Therefore, for the sake of simplicity, the day-ahead market is here modelled in a unit-commitment fashion.

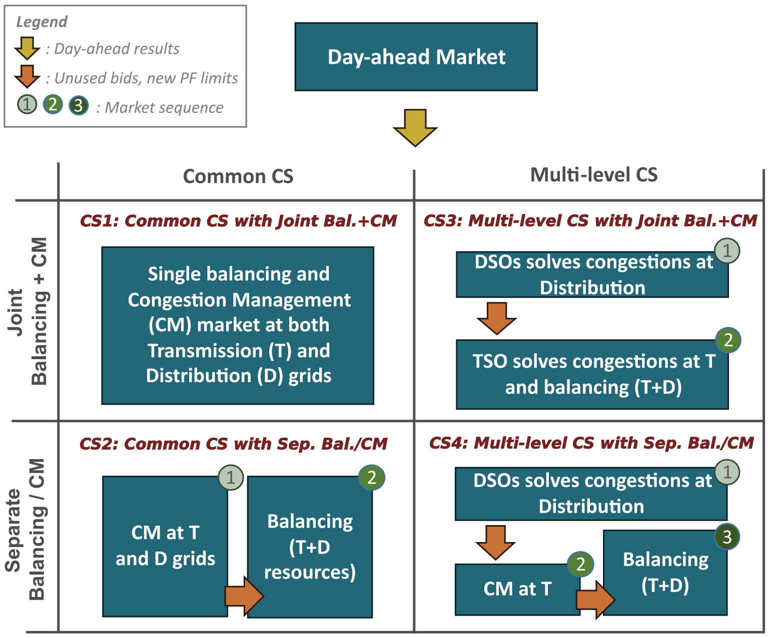

Figure 3.2: Overview of the four CSs analyzed.

At this market phase, the network is not considered, except for the limits between bidding zones, denoted by $NTC_{z,zz}$. Therefore, the DA minimizes the generation cost (3.1a)[2], ensuring that the total demand within the bidding zone is supplied by the generation in $pda_{g,h}$ while accounting for imports from and exports to other bidding zones (3.1b), captured by variable $tc_{z,zz,h}$. Equation (3.1c) computes the day-ahead dispatch that will later be passed on to the following CSs. Equations (3.1d)-(3.1f) are responsible for the unit commitment logic (based on Tejada-Arango et al. (2020)). Equation (3.1g) accounts for any minimum uptime if applicable to the generator g (e.g. nuclear or thermal power plants), while (3.1h) accounts for the minimum technical dispatch. Equation (3.1i) limits the output of renewable generators to their profile, represented by $ResProfile_{g,h}$. Finally, (3.1j) and (3.1k) restrict transfer capacity between bidding zones and power output per generator to their limits, respectively.

$$\min \sum_{g,h} \left[\left(Bid_g \cdot pda_{g,h}\right) + \left(su_{g,h} \cdot Cyc_g \cdot Q_g^{+}\right) \right] \tag{3.1a}$$

s.t.

$$\sum_{g \in ZG} pda_{g,h} - \sum_{zz \in IZ} tc_{z,zz,h} + \sum_{zz \in IZ} tc_{zz,z,h} = \sum_{i \in ZN} D_{i,h} : (\lambda_{z,h}) \quad \forall z, h \tag{3.1b}$$

[2]Both energy bids and cycling costs are considered, simulating complex bids or minimum-income bids in the day-ahead market.

$$dda_{i,h} = \sum_{g \in IG} pda_{g,h} \quad \forall i, h \tag{3.1c}$$

$$uc_{g,h-1} = uc_{g,h} - su_{g,h} + sd_{g,h} \quad \forall g, h \tag{3.1d}$$

$$pmax_{g,h} = uc_{g,h} \cdot P_g^+ \quad \forall g, h \tag{3.1e}$$

$$pda_{g,h} \leq pmax_{g,h} \quad \forall g, h \tag{3.1f}$$

$$su_{g,h} \cdot Minup_g \leq \sum_{h}^{h+minup_g} uc_{g,h} \quad \forall g, h \tag{3.1g}$$

$$uc_{g,h} \cdot P_g^+ \cdot MinDispatch_g \leq pda_{g,h} \quad \forall\, g, h \tag{3.1h}$$

$$pda_{g,h} \leq P_g^+ \cdot ResProfile_{g,h} \quad \forall h, g \in RES \tag{3.1i}$$

$$NTC^-_{z,zz} \leq tc_{z,zz,h} \leq NTC^+_{z,zz} \quad \forall z, zz, h \tag{3.1j}$$

$$pda_{g,h} \leq P_g^+ \quad \forall g, h \tag{3.1k}$$

Following the DA market, the flexibility market(s) take place based on the results of the DA market. Hence, the optimal dispatch for all generators (captured by variable $dda_{i,h}$) is passed on as the parameter $DispatchDA_{i,h}$ to all subsequent flexibility markets in all CSs. The dispatch is passed on aggregated for each node (3.1l).

$$DispatchDA_{i,h} = dda^*_{i,h} \quad \forall i, h \tag{3.1l}$$

3.2.2 Common Joint CS

In this Common Joint CS, the market solves all imbalances and network congestions using resources connected to both transmission and distribution networks. In this case, a single minimisation problem is solved. Equation (3.2a) minimizes the total cost of the FSPs activation during 24h, given by the bid Bid_k offered by FSPs and the flexibility dispatched $p_{k,h}$ in each direction (up and downwards). It is worth mentioning that for both up and downward regulation, the prices and quantities are set as positive values. Different approaches can be adopted when setting the cases studies to account for different market design options and market conditions. For instance, it could be the case that most downward balancing bids are set as negative prices, meaning that the SO has a revenue when activating the downward flexibility, which is the common situation in several existing balancing markets. However, it could also be the case that downward balancing bids are positive, meaning that the FSPs get paid to reduced generation or increase demand.

This situation is more common in LFMs (such as observed in Piclo data), or for some countries in TSOs markets (ACER, 2021).

The objective function also considers the possibility of Non-Served Flexibility (NSF), captured by $nsf_{i,h}$ and penalized by $CNSF$[3]. The NSF concept introduced in this chapter represents a state in which the SO cannot procure a certain volume of flexibility. In this case, the SO would resort to other mechanisms (e.g. network reconfiguration or curtailment to solve local congestions).

Considering that both congestion management and balancing markets are centrally run, this CS can be modelled as a single DC OPF. This DC OPF formulation introduces a small error in the power flow estimation; considering the X/R ratios of the networks under study (HV or EHV), this error may always be below 5% (Purchala et al., 2005). Additionally, the meshed characteristics of the HV distribution grid pose a challenge to normally used AC OPF relaxation methods for radial distribution grids. The use of full AC OPF would marginally contribute to the overall analysis proposed while being a complex nonlinear, non-convex problem. For these reasons, the DC OPF is used for both TSO and DSO networks. Losses are not considered in the formulation.

The demand balance equations (3.2b)-(3.2c) and the power flow equations are split according to the type of SO (3.2d)-(3.2e) (based on Lind et al. (2021c); and N. Savvopoulos et al. (2019)). In addition, (3.2f) and (3.2g) ensure that the power flow $f_{i,j,h}$ at the substation (the interface between TSO and DSO) is consistent. Equations (3.2h)-(3.2i) limit the maximum number of hours (in equivalence of power output) that DR FSPs (load-reduction only) can provide flexibility in order to account for comfort limitations in flexibility provision. For instance, demand response FSPs may be limited by $DRMax$ to providing flexibility to the equivalent of 4h per day. Equations (3.2j)-(3.2k) limit the upward and downward provision of flexibility from Renewable Energy Source (RES) in relation to their DA dispatch, given that these types of FSP may only have a limited capacity upward, especially (e.g. due to forecasting errors). Equations (3.2l)-(3.2r) are an implementation for the ESS, based on Niewiadomski and Baczyńska (2021), in which the state of charge $soc_{k,h}$ is computed considering the flexibility $p_{k,h}$ provided, the power charged or discharged ($pcha_{k,h}/pdis_{k,h}$) and the round efficiency EF.

Unit commitment equivalent formulation for the FSPs is defined in (3.2s)-(3.2w), as the binary variable $uc_{k,h}$ captures if the FSP is providing flexibility or not, and to which direction. Equation (3.2w), in particular, limits the flexibility provision to only one direction for each hour. It is worth mentioning that for the CSs modelled in this section, the same rationale for the choice of unit commitment type of formulation from the DA applies, namely the assumption of perfect competition and inelastic demand. Equations (3.2x), (3.2y) and (3.2aa) limit the power flow over the lines, the voltage phase angles in each node, and the maximum output per FSP in an OPF fashion, respectively. Finally, (3.2z) captures the flexibility of an FSP in both directions in a single variable $p_{k,h}$.

[3] The Cost of Non-Served Flexibility is set at 10k €/MWh, as a way to penalise NSF. This value is loosely associated to the typical costs for Non-Served Energy. Nevertheless, more precise studies could be done in order to calculate the especific CNSF for DSOs.

$$\min \sum_{s \in TS \wedge t=TSO,i,k,h} \Big[\Big(Bid_k^{up} \cdot p_{k,h}^{up}\Big) + \Big(Bid_k^{dw} \cdot p_{k,h}^{dw}\Big)\Big] + \sum_{s \in TS \wedge t=DSO,i,k,h} \Big[\Big(Bid_k^{up} \cdot p_{k,h}^{up}\Big) + \Big(Bid_k^{dw} \cdot p_{k,h}^{dw}\Big)\Big] + \sum_{i,h} \Big[\Big(nsf_{i,h}^{up} + nsf_{i,h}^{dw}\Big) \cdot CNSF\Big] \tag{3.2a}$$

s.t.

$$DispatchDA_{i,h} + \sum_{k \in IF} p_{k,h} - \sum_{j} f_{i,j,h} + \sum_{j} f_{j,i,h} - Imb_{i,h} = D_{i,h} + nsf_{i,h}^{p} - nsf_{i,h}^{n} \quad \forall i \in IS, (s \in TS) \wedge (t = TSO), h \tag{3.2b}$$

$$DispatchDA_{i,h} + \sum_{k \in IF} p_{k,h} - \sum_{j} f_{i,j,h} + \sum_{j} f_{j,i,h} - Imb_{i,h} = D_{i,h} + nsf_{i,h}^{p} - nsf_{i,h}^{n} \quad \forall i \in IS, (s \in TS) \wedge (t = DSO), h \tag{3.2c}$$

$$f_{i,j,h} = SB \cdot \frac{\theta_{i,h} - \theta_{j,h}}{X_{i,j}} \quad \forall (i \in IS, j \in IS) \in L, (s \in TS) \wedge (t = TSO), h \tag{3.2d}$$

$$f_{i,j,h} = SB \cdot \frac{\theta_{i,h} - \theta_{j,h}}{X_{i,j}} \quad \forall (i \in IS, j \in IS) \in L, (s \in TS) \wedge (t = DSO), h \tag{3.2e}$$

$$f_{i,j,h} = SB \cdot \frac{\theta_{i,h} - \theta_{j,h}}{X_{i,j}} \quad \forall (i,j) \in L \wedge [(i \in SUBS) \vee (j \in S\,U\,B\,S)], h \tag{3.2f}$$

$$\sum_{j} f_{j,i,h} = \sum_{j} f_{i,j,h} \quad \forall (i,j) \in SUBS, h \tag{3.2g}$$

$$\sum_{h} p_{k,h}^{up} \leq \sum_{h} P_{k,h}^{+} \cdot DRMax \quad \forall k \in DR \tag{3.2h}$$

$$\sum_{h} p_{k,h}^{dw} \leq \sum_{h} P_{k,h}^{-} \cdot DRMax \quad \forall k \in DR \tag{3.2i}$$

$$p_{k,h}^{up} \leq PDA_{k,h} \cdot MaxFlex_k^{+} \quad \forall k \in RES, h \tag{3.2j}$$

$$p_{k,h}^{dw} \leq PDA_{k,h} \cdot MaxFlex_k^{-} \quad \forall k \in RES, h \tag{3.2k}$$

$$soc_{k,h} = SoC^{init}_{k,h=1} + soc_{k,h-1} - \Big(pdis_{k,h} \cdot P^{+}_{k,h} \cdot EF + p^{up}_{k,h}\Big) + \Big(pcha_{k,h} \cdot P^{-}_{k,h} \cdot EF + k^{dw}_{f,h}\Big) \quad \forall\, k \in ESS, h \tag{3.2l}$$

$$soc^{-}_{k} \leq soc_{k,h} \leq soc^{+}_{k} \quad \forall k \in ESS, h \tag{3.2m}$$

$$p^{dw}_{k,h} = flexess^{dw}_{k,h} \cdot P^{+}_{f,h} \cdot EF \quad \forall k \in ESS, h \tag{3.2n}$$

$$p^{up}_{k,h} = flexess^{up}_{k,h} \cdot P^{+}_{k,h} \cdot EF \quad \forall\, k \in ESS, h \tag{3.2o}$$

$$bcha_{k,h} + bdis_{k,h} \leq 1 \quad \forall k \in ESS, h \tag{3.2p}$$

$$pdis_{k,h} + flexess^{dw}_{k,h} \leq bdis_{k,h} \quad \forall k \in ESS, h \tag{3.2q}$$

$$pcha_{k,h} + flexess^{up}_{k,h} \leq bcha_{k,h} \quad \forall k \in ESS, h \tag{3.2r}$$

$$p^{up}_{k,h} \leq P^{+}_{k,h} \cdot uc^{up}_{k,h} \quad \forall k, h \tag{3.2s}$$

$$p^{dw}_{k,h} \leq P^{-}_{k,h} \cdot uc^{dw}_{k,h} \quad \forall k, h \tag{3.2t}$$

$$uc^{up}_{k,h} \cdot MinBidSize \leq p^{up}_{k,h} \quad \forall k, h \tag{3.2u}$$

$$uc^{dw}_{k,h} \cdot MinBidSize \leq p^{dw}_{k,h} \quad \forall k, h \tag{3.2v}$$

$$uc^{up}_{k,h} + uc^{dw}_{k,h} \leq 1 \quad \forall k, h \tag{3.2w}$$

$$F^{-}_{i,j} \leq f_{i,j,h} \leq F^{+}_{i,j} \quad \forall i, j, h \tag{3.2x}$$

$$\theta^{-}_{i} \leq \theta_{i,h} \leq \theta^{+}_{i} \quad \forall i, h \tag{3.2y}$$

$$p_{k,h} = p^{up}_{k,h} - p^{dw}_{k,h} \quad \forall k, h \tag{3.2z}$$

$$P^{-}_{k} \leq p_{k,h} \leq P^{+}_{f} \quad \forall k, h \tag{3.2aa}$$

3.2.3 Common CS with Separate CM and Balancing

This CS is characterized by a central MO that solves congestions and balancing using sequential markets. Resources connected to the distribution and transmission networks participate in these markets.

Congestion Management

The congestion management market is modelled with a DC OPF. This model is similar to the Common Joint CS, although the demand balance equations (3.3c)-(3.3d) do not include the imbalances parameter $Imb_{i,h}$ (in comparison to the joint demand balance equations (3.2b)-(3.2c).

$$min \quad (3.2a) \tag{3.3a}$$

s.t.

$$(3.2d) - (3.2aa), \tag{3.3b}$$

$$\begin{aligned} DispatchDA_{i,h} + \sum_{k \in IF} p_{k,h} - \sum_{j} f_{i,j,h} + \sum_{j} f_{j,i,h} \\ = D_{i,h} + nsf^{p}_{i,h} - nsf^{n}_{i,h} \quad \forall i \in IS, (s \in TS) \wedge (t = TSO), h \end{aligned} \tag{3.3c}$$

$$\begin{aligned} DispatchDA_{i,h} + \sum_{k \in IF} p_{k,h} - \sum_{j} f_{i,j,h} + \sum_{j} f_{j,i,h} = D_{i,h} + nsf^{p}_{i,h} - nsf^{n}_{i,h} \\ \forall i \in IS, (s \in TS) \wedge (t = DSO), h \end{aligned} \tag{3.3d}$$

After the congestion management market closes, FSP's minimums and maximums in terms of active power are adjusted and passed on to the balancing market, as exemplified in (3.3e).

$$P^{new+}_{k,h} = P^{+}_{k,h} - p^{*}_{k,h} \quad \forall k, h \tag{3.3e}$$

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 (3.4c)-(3.4d) and considering the new limits received from the congestion management market. Although balancing markets do not always include network constraints, the OPF formulation is used as a representation of a power flow check by the TSO and adjustments to the balancing market results. As a simplification, bids from at both congestion management market and balancing market are the same.

$$min \quad (3.2a) \tag{3.4a}$$

s.t.

$$(3.2d) - (3.2aa), \tag{3.4b}$$

$$\sum_{k \in IF} p_{k,h} - \sum_j f_{i,j,h} + \sum_j f_{j,i,h} = \sum_i Imb_{i,h} \quad \forall i \in IS, (s \in TS) \wedge (t = TSO), h \tag{3.4c}$$

$$\sum_{k \in IF} p_{f,h} - \sum_j f_{i,j,h} + \sum_j f_{j,i,h} = \sum_i Imb_{i,h} \quad \forall i \in IS, (s \in TS) \wedge (t = DSO), h \tag{3.4d}$$

3.2.4 Multi-Level CS

In the Multi-level implementation, first, the DSO runs a LFM, and then the TSO run the congestion and balancing markets. For the LFM, two different implementations are proposed. The first one is based on an OPF for the distribution network. The second proposal for the LFM implementation is a reduction of the problem, considering just the power flows at the interface substations; this approach replicates a real LFM implemented in Sweden (Ruwaida et al., 2023).

Local Flexibility Market – OPF

In the LFM, the DSO minimizes the cost of activating resources connected to the distribution grid to solve local congestions. The objective function (3.5a) minimizes the cost of procuring flexibility, and the eventual penalties for surpassing the subscription limit at the substation captured by variable $subscost_{s,h}$, and the total cost of NSF. The demand balance equations for this market consider the results of the day-ahead market: generation and demand for each bus of the DSO's network, and the power flow expected at the interfaces with the TSO. The virtual demand variable $vd_{s,h}$ captures the power to be imported (or exported, in case of a DG-driven grid) from/to the TSO. The virtual demand is then allocated to each interfacing substation between the DSO and the TSO grids. This allocation is calculated as the product of the $vd_{s,h}$ and the average of the Power Transfer Distribution Factors (PTDFs) of all the DSO grid nodes in relation to the corresponding substation[4]. This average value is set in the parameter $Impact_i$. This process aims at reproducing the internal forecasting performed by the DSO in order to compute the power flow at each substation when considering the local market. This inclusion is required as meshed-to-meshed topologies are considered in the model. In the case of a radial distribution network, $Impact_i$ is expected to always be 1 for the single interface $i \in SUBS$. Therefore, equations (3.5c)-(3.5f) compute and allocate the power flows at the interfaces.

[4] For the calculation of the PTDFs, the slack buses are placed in nodes far enough from the distribution grid.

$$min \sum_{s \in TS \wedge t=DSO,i,f,h} \left[\left(Bid_k^{up} \cdot p_{k,h}^{up} \right) + \left(Bid_k^{dw} \cdot p_{k,h}^{dw} \right) + subscost_{s,h} + \left(nsf_{i,h}^{up} + nsf_{i,h}^{dw} \right) \cdot CNSF \right] \tag{3.5a}$$

s.t.

$$(3.2c), (3.2e) - (3.2aa), \tag{3.5b}$$

$$fsubs_{i,h} = \sum_{j \notin SUBS} f_{i,j,h} - \sum_{j \notin SUBS} f_{j,i,h} \quad \forall\, i \in (IS, SUBS),\ (s \in TS) \wedge (t = DSO), h \tag{3.5c}$$

$$fsubs_{i,h} = vd_{s,h} \cdot Impact_i \quad \forall\, i \in (IS, SUBS), (s \in TS) \wedge (t = DSO), h \tag{3.5d}$$

$$fsubs_{i,h} = \sum_{lv} lvsubs_{i,lv,h} \quad \forall\, i \in (IS, SUBS), (s \in TS) \wedge (t = DSO), h \tag{3.5e}$$

$$subscost_{s,h} = \sum_{i,lv} lvsubs_{i,lv,h} \cdot CSubs_{i,lv} \quad \forall (s \in TS) \wedge (t = DSO), h \tag{3.5f}$$

After the LFM, the information of activated FSPs and not allocated bids are passed on to the TSO (as in (3.3e)). Unused bids, however, are only passed on to the TSO if they would not lead to further congestions at the distribution grid. It is to say that the TSO cannot activate FSPs in the direction opposite to the direction they were activated by the DSO. Moreover, the information on the activated FSPs is sent to the TSO as the parameter $DispatchFSP_{k,h}$ (3.5g). This is done so this SO can consider DSO activations when forecasting the necessary power to be delivered at the interfaces (3.7c). This formulation also limits the need for information exchange between TSO and DSO. From the LFM to the TSO market(s), only unused bids, activation information and direction limitation are transferred. No grid information is transferred, considering that both SOs forecast the power at the interface substations based on, firstly the DA market, and secondly the LFM.

$$DispatchFSP_{k,h} = p_{k,h}^{*} \quad \forall\, k, h \tag{3.5g}$$

Local Flexibility Market – PTDF-Based

An alternative formulation of the LFM aims to replicate a Swedish implementation of the LFM (Cossent et al., 2022). The DSO considers the impact of each demand, generation, and FSP activation over the substation using PTDFs only. This computation is carried out in (3.6c)-(3.6d). It is, therefore, a simplification of the full OPF-Based LFM, as the DSO only solve overloading of the interfacing substations. Despite being a simplification and therefore neglecting the full power flow at all elements, this market model has the advantage of being simpler to clear and to communicate. In this case, FSPs would know their PTDF with respect to the congestion, providing them with complete information about the market clearing. In the Swedish case in question, this is used to overcome subscription penalties. Nevertheless, this market model can be easily extended to LFMs in which only the PTDFs of the structurally congested elements are considered in the clearing process and made available to FSPs.

$$min \quad (3.5a) \tag{3.6a}$$

s.t.

$$(3.2g) - (3.2aa), (3.5e) - (3.5f) \tag{3.6b}$$

$$\begin{aligned} pfsub_{i \in SUBS,j,h} = \Bigg[& - \sum_{ii} DispatchDA_{ii,h} - \sum_{i,k} p_{k \in\, I\, F,h} + \sum_{ii} D_{ii,h} + \sum_{i} nsf^{up}_{ii,h} \\ & - \sum_{i} nsf^{dw}_{ii,h} \Bigg] \cdot PTDF_{i,j,ii} \quad \forall\, i \in (IS, SUBS), j, (s \in TS) \wedge (t = DSO), h \end{aligned} \tag{3.6c}$$

$$fsubs_{i,h} = \sum_{j} pfsub_{i \in SUBS,j,h} \quad \forall\, i \in (IS, SUBS),\ (s \in TS) \wedge (t = DSO), h \tag{3.6d}$$

TSO Market (Joint procurement)

Following the DSO LFM (either the OPF-based or the PTDF-based formulation), the TSO runs their markets. In the following formulation, the joint balancing and congestion management market are described. Equation (3.7c) computes the "virtual demand" that the TSO has to deliver to the DSO for the joint CS. Considering that we focus on HV distribution grids and those can be meshed, there could be multiple TSO-DSO interfaces for a single distribution grid. In this context, the virtual demand must be distributed to the different TSO-DSO interfaces. To do that, it is considered that the power flow on the interfaces will follow a typical impact factor for each substation, therefore allowing the TSO to forecast the power flow at the interfaces. This impact factor is an average of the PTDFs of the nodes in the distribution grid in relation to the interface substations. This method intends to account for what, in reality, would be the forecasting process of the TSO. This process of allocating the virtual demand to the interface substations is formulated in (3.7d)-(3.7g). It considers the same parameter $Impact_i$ as in the LFM formulations.

The model below describes the joint TSO market in the Multi-level CS only. Nevertheless, the separate TSO markets in the Multi-level CS follow the same logic as in the Common separate CS, in which the parameter Imb_{gh} is not included in the supply-demand balance constraint (3.7c), followed by the balancing market that includes Imb_{gh} but not $DispatchDA_{ih}$ and D_{ih}, in a similar way as in (3.3c) and (3.4c).

$$min \quad (3.2a) \tag{3.7a}$$

s.t.

$$(3.2b), (3.2d), (3.2g) - (3.2aa), \tag{3.7b}$$

$$\begin{aligned} -\sum_i DispatchDA_{i,h} + \sum_i D_{i,h} + \sum_i Imb_{i,h} - \sum_{i \in IF} p_{k,h} - \sum_k DispatchFSP_{k,h} \\ + \sum_i nsf^{up}_{i,h} - \sum_i nsf^{dw}_{i,h} = vd_{s,h} \quad \forall\, i \in\ IS, (s \in TS) \wedge (t = DSO), h \end{aligned} \tag{3.7c}$$

$$\sum_{j \in (L,SUBS)} f_{j,i,h} = fimport_{i,h} \quad \forall i \in (IS, SUBS), (s \in TS) \wedge (t = DSO), h \tag{3.7d}$$

$$fimport_{i,h} = vd_{s,h} \cdot Impact_i \quad \forall i \in (IS, SUBS), (s \in TS) \wedge (t = DSO), h \tag{3.7e}$$

$$fimport_{i,h} = fexport_{i,h} \quad \forall\, i \in SUBS, h \tag{3.7f}$$

$$-\sum_j f_{i,j,h} + \sum_j f_{j,i,h} = fexport_{i,h} \quad \forall\, i \in (IS, SUBS), (s \in TS) \wedge (t = TSO), h \tag{3.7g}$$

3.3 Swedish Case Study

A case study is used to validate the previous formulations of different CSs for Congestion Management, considering both a simplified transmission model for the whole country and a subtransmission model for the Uppsala region in Sweden.

In Sweden, the regional DSO operates the subtransmission network and is currently required to procure distributed flexibility, as they are subject to subscription limitations at their interfaces with the TSO (Ruwaida et al., 2023). The subscription limits are virtual power flow limitations imposed at the substation level. The DSOs in Sweden may request annual and temporal subscription level raises at lower costs. However, since 2016 several DSOs have been denied such raises (Ruwaida et al., 2023). In these cases, if subscription levels are surpassed, the DSO incur into penalties. Hence, DSOs in Sweden are experimenting with procuring local flexibility in order to avoid potential penalties.

The Swedish transmission grid used in the case study is an adapted version of the Nordic 32 (Van Cutsem et al., 2020). This 32-node test system is a representation of the Swedish transmission grid, incorporating international connections to the Nordic system. Additional modifications are incorporated in this test system to improve its robustness and representativeness, such as the increase of installed capacity to current levels, locations of generation and load and wind penetration (Müller, 2019; Thorslund, 2017).

The original Nordic 32 test system, as presented in Van Cutsem et al. (2020), is divided into four areas, namely North, Central, South, and Equiv., the latter being a representation of the connection of Sweden with the rest of the Nordic System. Figure 3.3 presents the original implementations of the Nordic 32 with the representation of the four mentioned zones.

A subtransmission grid is incorporated into the aforementioned transmission network. This subtransmission grid is a representation of the 70 kV network of Uppsala region, one of the demonstration sites in the H2020 CoordiNet project (Cossent et al., 2022). Figure 3.4 provides some schematics of the distribution grid considered.

Regarding the load and generation parameters, 2020 is used as the base year (Svenska kraftnät, 2022). The load profiles for the whole year are clustered into eight representative days using a k-means clustering method (Hartigan and Wong, 1979). Two representative days are obtained per season, representing high- and low-load periods, as illustrated in Figure 3.5.

The Swedish wholesale market has four different bidding zones; renewable energy output is aggregated in each bidding zone. The NTC between bidding zones considered is the maximum NTC calculated by ENTSO-e and published by Nord Pool (ENTSO-E, 2021a).

The cost for each generation technology is obtained from Jensen and Pinson (2017). For wind farms and solar power plants, the variable cost considered is close to 1 €/MWh, as no fuel costs exist, although other operational costs (e.g. maintenance) do exist. Hydropower plants follow the yearly profile observed in 2020, as water-value constraints are not included in the DA market. Additionally, the cycling costs from Jensen and Pinson (2017) are also used. It is important to highlight that the objective of the present analyses is not to forecast actual costs for SOs, but rather to study the rate of change under the different sensitivity scenarios.

3.3.1 Results from the Day-Ahead Market

The results from the DA will determine the congestion alleviation needs that need to be considered afterwards in the individual CSs. For this reason, the obtained results from the DA market for one year are compared with the actual DA market results in terms of the energy mix and average price. Technologies such as nuclear and thermal units will have a minimum dispatch restriction (Jensen and Pinson, 2017); a "must-run" option is added for nuclear generation, considering that the model runs eight individual representative days without constraints connecting them. Using these assumptions, the calculated generation reaches satisfactory comparability with the actual generation in Sweden in the year 2020, as shown in Table 3.1. The difference in total energy gen-

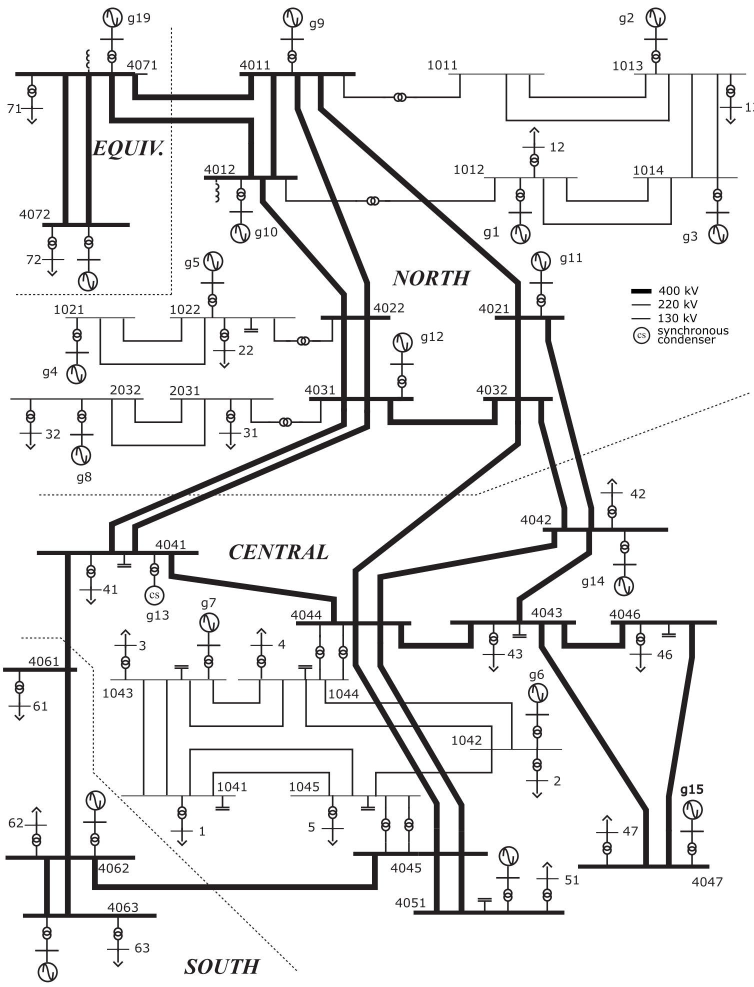

Figure 3.3: Nordic 32 transmission grid. Source: Van Cutsem et al. (2020).

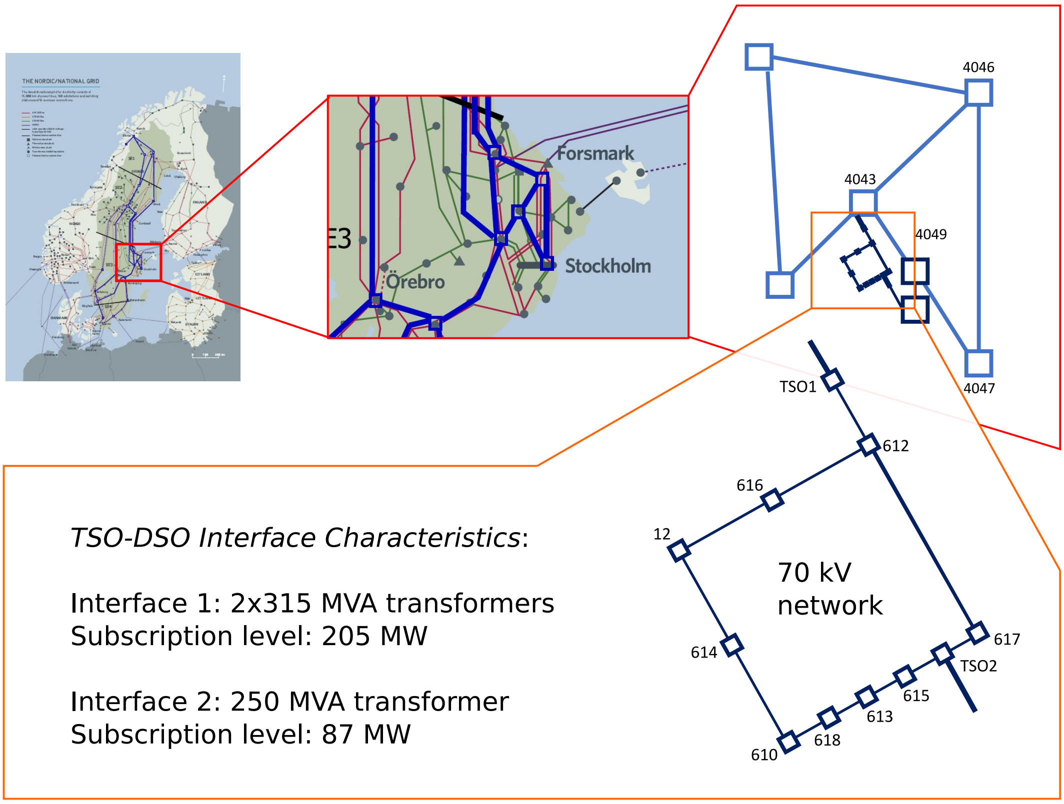

Figure 3.4: Location and representation of the 70 kV Uppsala grid.

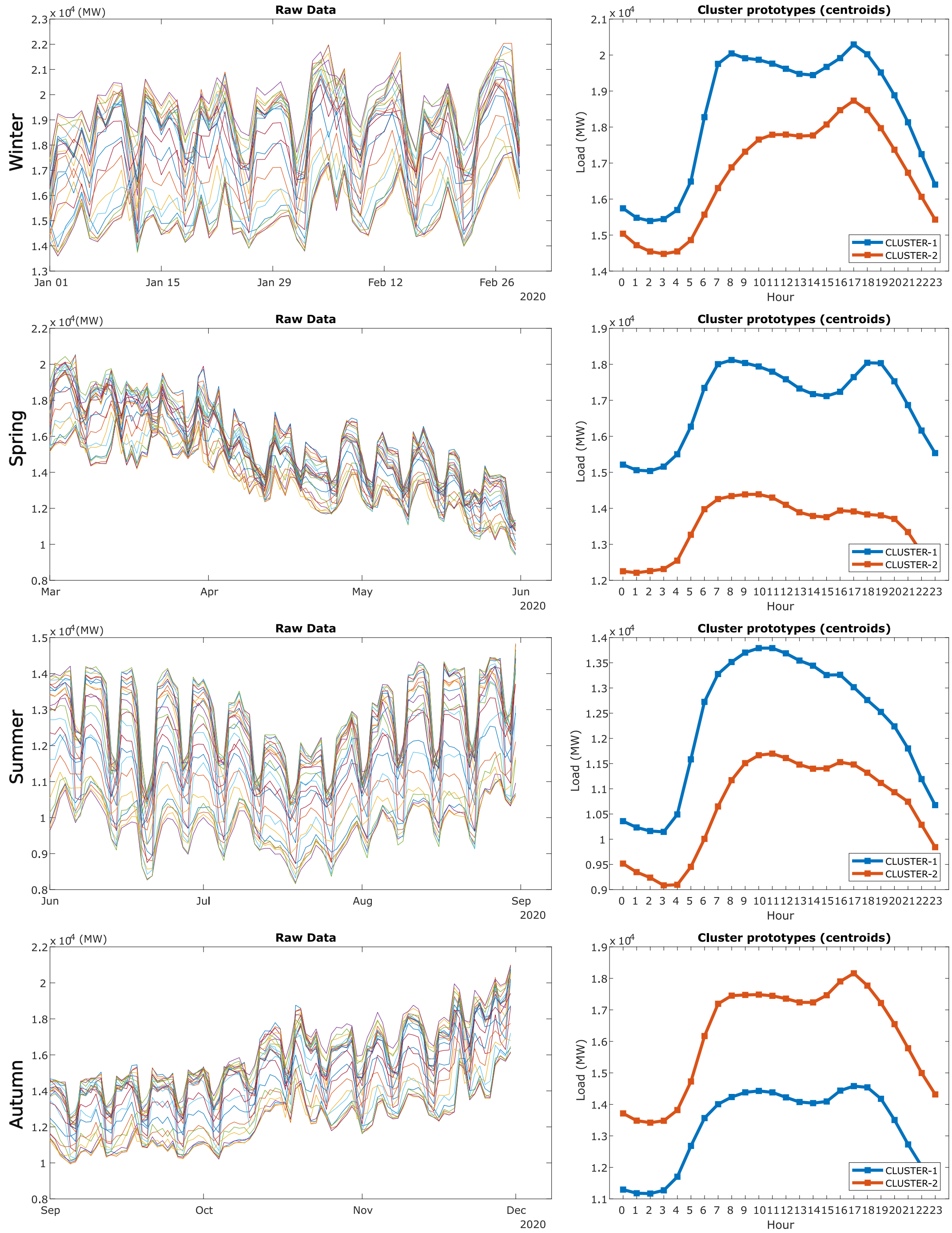

Figure 3.5: Clustering of demand for Sweden in 2020.

erated by the model (141 TWh) compared with the actual generation (153 TWh) is due to the higher export of energy to the neighborhood systems, which are not modelled in detail.

Technology	Model Output		Actual Gen. Mix	
	TWh	% Mix	TWh	% Mix
Thermal	3	2%	6	4%
Hydro	68	48%	72	47%
Nuclear	43	31%	47	31%
Wind	27	19%	28	18%
Total	141 TWh		153 TWh	

Table 3.1: Comparison between model output and actual generation mix in Sweden in 2020.

In order to evaluate the different CSs, appropriate scenarios of congestion management and balancing needs are required. As mentioned above, the overall need for congestion management is generated by the DA dispatch and the network capability; thus, the congestions from the DA market are the same in every CS.

According to ACER (2021), the total volume of remedial actions (measures taken to solve intra-bidding zone congestion) in 2020 in Sweden was 69.2 GWh, and the total cost was 1.14 million euros. These values are taken as a reference for validating the volume of congestion management needs generated by simulations. The balancing needs are included as an input of the model assigned per node of the grid based on the results of the DA clearing. In order to calculate the amount of balancing needs and in which direction, data from the ENTSO-E transparency platform is used (ENTSO-E, 2022b). It is observed that imbalances in Sweden totalled approximately 3 TWh in 2020.

3.3.2 Scenarios

The flexibility available for the different market sessions in the different CSs is offered by resources connected at both transmission and distribution grids. The FSPs connected to the transmission grid are the same generators that participate in the DA market. Their capability to offer flexibility will depend on their scheduled volume in the DA market and their technology. We assume that wind farms can only offer 5% of their DA schedule upwards, considering that there are differences between their DA forecasts and the real-time generation (Algarvio et al., 2019; Martín-Martínez et al., 2018). Solar power plants cannot offer upward flexibility, only downward. In terms of bidding, these units bid the same variable cost as they offered to the DA market. In this context, we assume that the FSPs are participating under perfect competition and act as naïve agents and therefore bid their real short-term variable cost, considering the scope of this chapter.

In the Swedish case, the FSPs connected to the distribution grid are based on the FSPs participating in the CoordiNet project (Etherden and Ruwaida, 2020). Table 3.2 lists the type of FSP and their capacity to offer upward and downward flexibility. The minimum bid size considered is 0.1 MW. One battery is included, with an energy capacity of 20 MWh and a flexibility capacity of 5 MW, having to comply with the State of Charge (SoC) formulations (24)-(30). The round-trip efficiency considered is 80% (EIA, 2021).

Different sensitivities are studied in order to evaluate the effects of increased demand, increase in available distributed flexibility, and changes in flexibility bids offered by FSPs. Sensitivity factors

FSP	BUS	FSP type	Downward flexibility (MW)	Upward flexibility (MW)	Bid price (€/MWh)
1	612	Battery (20 MWh)	5	5	8
2	613	Office buildings	0	0.5	10
3	12	Multi-family housings	0	0.5	16
4	610	Commercial building	0	0.5	12
5	613	District heating	5	30	20
6	613	Multi-family housings	0	0.5	16
7	613	Industry	0.5	1	16
8	614	Industry	0.5	1	16

Table 3.2: FSPs connected to the Uppsala grid in Sweden; Base case flexibility.

are applied to selected parameters of the optimisation models, as presented in Table 3.3. The sensitivity range shows the values to which parameters are multiplied in the sensitivity analysis.

Parameter	Considerations	Sensitivity range	Sensitivity purpose
$P_k^{+,-}$	Applied only to FSPs connected at the distribution grid	$[0 \quad 0.2 \quad \dots \quad 2.8 \quad 3]$	Study different levels of distributed flexibility provision available to the DSO and TSO.
$Bid_k^{up,dw}$	Applied only to FSPs connectedat the distribution grid	$[0 \quad 0.2 \quad \dots \quad 2.8 \quad 3]$	Study different costs of distributed flexibility.
D_{ih}	Applied only to the load connected to the distribution grid	$[0.8 \quad 0.9 \quad \dots \quad 1.9 \quad 2]$	Study different scenarios of demand growth at distribution grids.

Table 3.3: Sensitivity factors for scalability analysis.

The replication scenarios considered for the Swedish case are two, namely, the different CSs and the types of FSPs. The latter proposes an exercise in connecting different types of FSPs not observed in the Swedish network being analyzed. In this case, two wind farms are connected to the distribution grid.

3.3.3 Results

When comparing the total cost for a scenario with no flexibility being provided by the FSPs at the distribution grid with the base case scenario, it is possible to verify a significant cost reduction for the DSO, from 1,674 k€ per year to 802 k€(Multi-level PTDF CS). It is worth noticing that these results for both the "no-flexibility" and the "base case" scenarios are comparable to a real-life demonstration carried out within the CoordiNet project, which estimated costs of 1,434 k€ and 895 k€, respectively, validating the model used (Trakas et al., 2022). In a scenario with no flexibility, the totality of the cost would be related to the potential penalties associated with surpassing subscription levels. Table 3.4 presents the results for both scenarios, as well as the replication scenarios comparing different CSs.

Coordination Scheme	No-Flexibility Scenario	Base Case Scenario
Common		
Joint	13,095	11,658
Separate	13,793	12,481
Multi-level (OPF)		
Local	1,674	713
Joint	11,913	11,937
Separate	12,751	12,767
Multi-level (PTDF-Based)		
Local	1,817	802
Joint	11,913	11,937
Separate	12,751	12,769

Table 3.4: Comparison between the "No-flexibility" and the "Base Case" scenarios in Sweden. In k€/year.

When comparing the results from the different CSs, it is possible to observe that the common market model would lead to the least total cost of flexibility procurement, considering that for both implementations of the multi-level CS[5], in line with current research on TSO-DSO coordination models (Marques et al., 2023). It is also noticeable that the subscription limitation works as a transferring mechanism of congestion costs from the TSO to the DSO, as observed in the No-Flexibility Scenario. It showcases the use of virtual congestions and financial incentives as a way of congestion management cost allocation, as a price signal is given from the TSO to the DSO indicating that a higher withdrawn at the interface substation would lead to higher congestions somewhere in the transmission grid.

Table 3.5 presents the results in terms of energy activated for the demonstration scenario. This “demonstration scenario” considers the base case flexibility and the "Multi-level (PTDF-based)" CS. Values presented are in GWh/year, as results per representative day are already multiplied by the number of times the representative day takes place in one year. We observe that there are activations due to congestion management only during the winter representative days. The DSO activates 10 GWh of flexibility in its LFM, which represents 0.69% of the total energy supplied by the distribution grid. On the other hand, the TSO activates approximately 3.6 TWh, from which 3 TWh is due to balancing needs and 0.6 TWh due to congestion alleviation.

Figure 3.6 presents the results for the scenario in which sensitivity factors are applied to the sizes and bids of the FSPs connected to the distribution network. The costs shown are for the DSO in the LFM. The sensitivity factor in the x and y axes of the graph are those defined in Table 3.3, where a sensitivity factor of 1 represents the base case scenario. In the curved surface of the graph, it is possible to identify the "no-flexibility" and the "base case" scenarios discussed above and presented in Table 3.4. Moreover, this sensitivity analysis reveals that if the capacity of the FSPs in the demo is scaled up to a factor of 1.6, subscription penalties are eliminated by the procurement of local flexibility.

The sensitivity scenario explores the effects of increasing the demand connected to the distribution grid. In this scenario, we run a sensitivity factor over the demand and the size of FSPs in the distribution grid and explore the concept of NSF. The NSF is the situation in which the DSO

[5] The LFM cost has to be added to either the joint or separate TSO markets in order to make costs comparable.

SO Market Product/Direction	Winter		Spring		Summer		Autumn		Total Year
	High	Low	High	Low	High	Low	High	Low	
DSO LFM	**9**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**10**
CM	9	1	0	0	0	0	0	0	10
Up.	9	1	0	0	0	0	0	0	10
TSO Markets	**1,008**	**368**	**338**	**427**	**438**	**320**	**326**	**420**	**3,645**
Balancing	400	341	337	427	438	320	326	420	3,009
Down.	189	175	132	98	153	138	154	164	1,203
Up.	211	166	206	329	285	182	172	256	1,807
CM	608	27	0	0	0	0	0	0	635
Down.	308	14	0	0	0	0	0	0	323
Up.	300	13	0	0	0	0	0	0	313

Table 3.5: Demonstration scenario for Swedish case study: Energy activated. In GWh/year.

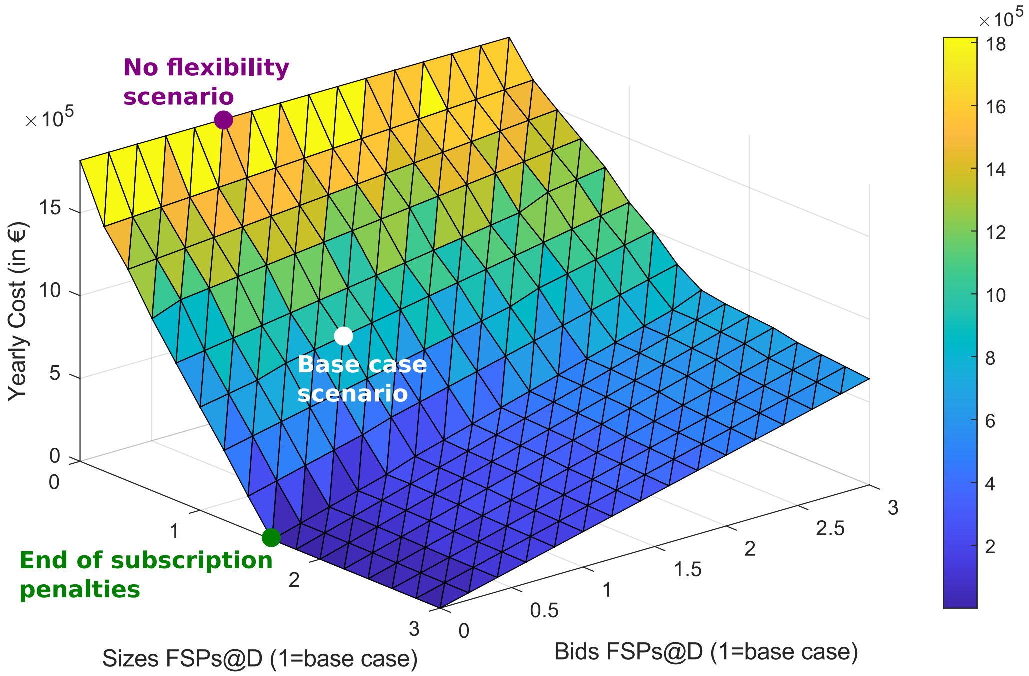

Figure 3.6: Sensitivities to size and bids of FSPs connected at distribution (FSPs@D). DSO costs in the Multi-level (PTDF-Based) LFM.

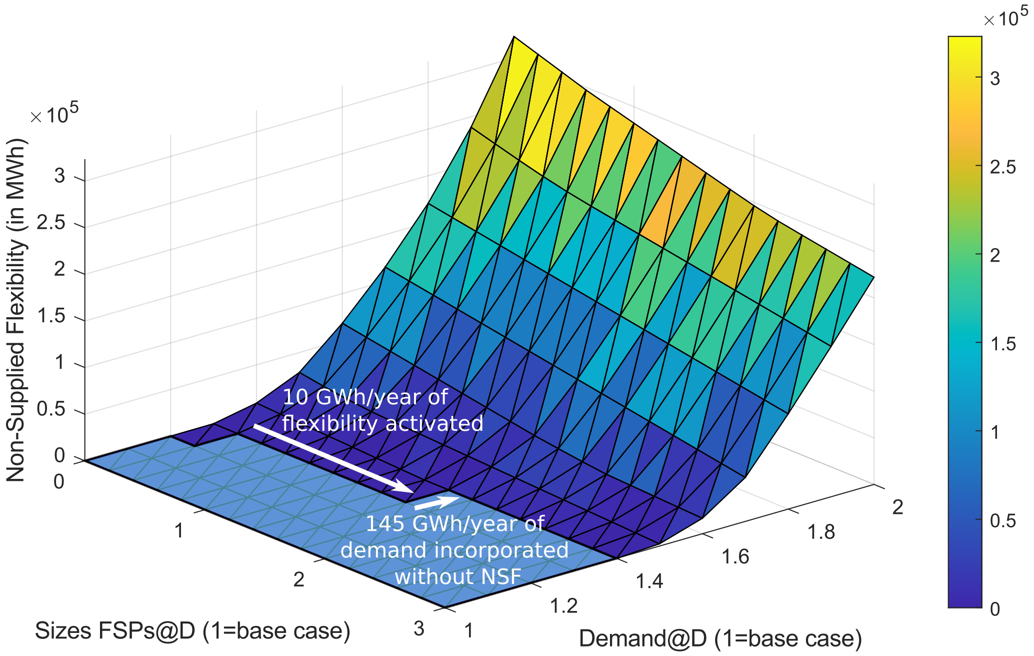

Figure 3.7: Sensitivity to demand connected to distribution (Demand@D) and size of FSPs connected at distribution (FSPs@D). Non-Supplied Flexibility for DSO in Multi-level (OPF) LFM.

has congestions in its grid and wants to procure flexibility to solve these congestions, but the flexibility available in the market is not sufficient or not effective for that purpose. In that case, the DSO would have to use other mechanisms to ensure the secure operation of the grid (e.g. change in topology, and/or curtailment of selected generation or demand units). Figure 3.7 presents the result of this sensitivity analysis.

The flat light-blue area on the graph represents the region in which either the DSO does not have any congestion in the network or, if congestions exist, they can be solved by the available flexibility in the LFM. Outside the flat area is the region in which the DSO observes some amount of non-supplied flexibility. It is important to note, though, that this analysis considers only congestions due to thermal limits of lines and transformers and not needs due to subscription penalties (which already exist at the current load level). For this reason, this scalability scenario considers the CS Multi-level (OPF-Based), which also accounts for the power flow in every line in the grid, and not only the power flow at the substation as the Multi-level (PTDF-Based).

This analysis reveals that an increase of 10 GWh of activated flexibility per year would allow the incorporation of 145 GWh of demand (10% for that subtransmission grid) without leading to an NSF situation. For the DSO, this could mean that grid reinforcement needed in the face of demand growth could be deferred using local flexibility, for instance.

Finally, the replication case is studied, in which two wind farms are connected into the case study at the DSO network. The addition of the two wind farms consistently reduces the total costs for the TSO by approximately 2%. For the DSO, however, the costs can be reduced by up to 98%. This is since incorporating the two new DERs in the DSO's grid not only increases the flexibility available but also means that distributed generation is included in this grid in the first place. The DER helps to offset the need for importing energy from the TSO through the TSO-DSO interfaces, which leads to a significant reduction in subscription penalties. Table 3.6 presents the results from the replication scenario.

Coordination Scheme	Base Case	Replication Scenario	%
Common			
Joint	11,658	11,369	-2.5%
Separate	12,481	12,197	-2.3%
Multi-level (OPF)			
Local	713	12	-98.3%
Joint	11,937	11,674	-2.2%
Separate	12,767	12,514	-2.0%
Multi-level (PTDF-Based)			
Local	802	23	-97.2%
Joint	11,937	11,683	-2.1%
Separate	12,769	12,521	-1.9%

Table 3.6: Replication scenario. Wind Farms incorporated to Sweden case study. In k€/year.

3.4 Spanish Case Study

For the purpose of studying the scalability and replicability in Spain, a simplified test-case network is built, considering both a simplified transmission model for the whole country and a high-voltage model for both the Cádiz and the Albacete regions.

The simplified transmission network used in this study is the 11-node "small Spanish system" developed for use with the openTEPES[6] model (Ramos et al., 2022). Together with the model, the authors also publish the complete data set for the small Spanish system, a case study focused on the transmission expansion planning for the 2030 scenario. Therefore, this case study had to go through the necessary adaptations in order to better reflect the current Spanish power system. The adaptations made were mostly related to the installed capacity mix, as the 2030 scenario considers a higher penetration of RES and lower installed capacity of thermal generators (Red Eléctrica de España, 2021). In relation to the network, two adaptations were made. First, candidate lines for the transmission expansion problem were disregarded. Second, the model considered a double circuit from nodes T8 to T10. This double circuit was split into one circuit from T8 to T10 and another from T8 to T6, in order to accommodate the Albacete subtransmission grid. The Cádiz network is directly connected to node T5 of the transmission grid. Figure 3.8 provides an illustration of the final Spanish test system used in this study.

[6]The openTEPES is an open-source optimisation model for transmission and generation expansion planning.

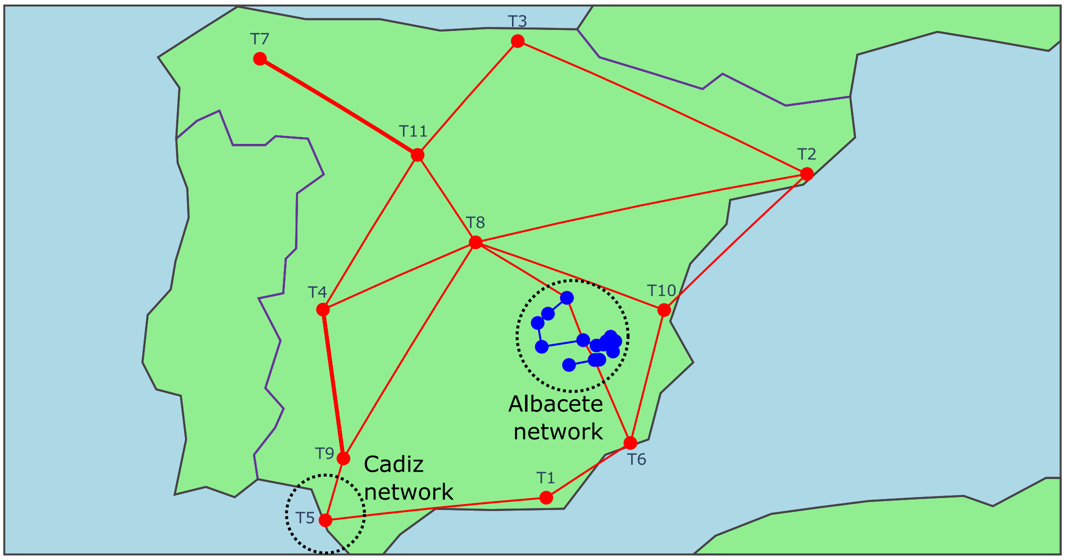

Figure 3.8: Spanish test system.

Albacete Network

The Albacete subtransmission grid consists of two 132 kV networks connected to the transmission grid. These networks were produced based on the network maps published by the Spanish TSO and typical electrical parameters for the lines provided by the demonstration partners of the CoordiNet project. Figure 3.9 depicts the complete network map (on the left) and the modelled section of the grid (on the right). The first DSO network (upper network) consists of a ring with two interfaces with the TSO to which load and generation are connected, together with a radial network exclusively used by wind farms. The second grid (lower on the figure) consists of only two nodes and the corresponding substation. These lines connect RES generators.

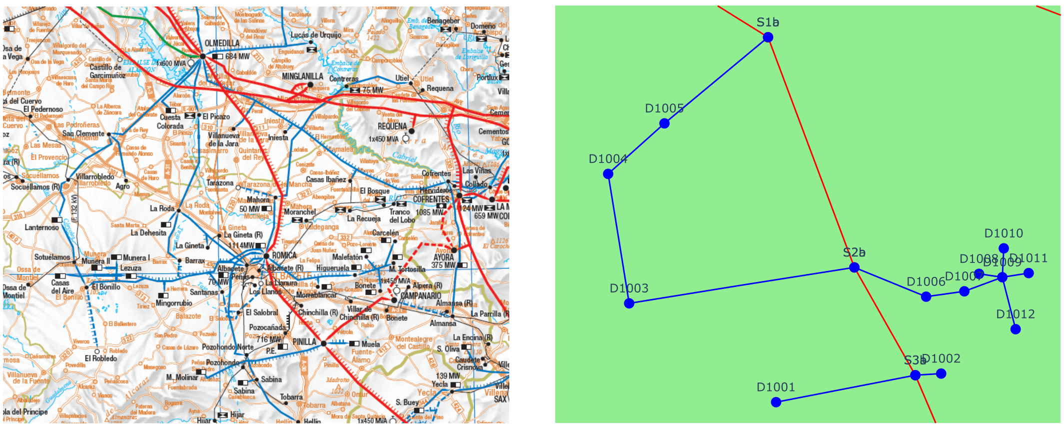

Figure 3.9: Albacete subtransmission network. Source (map on the left): Red Eléctrica de España (2015).

Cádiz Network

The information on the Cádiz network used in this study was provided by the Spanish DSO e-DI[7] in the context of the CoordiNet project. Considering that the network data did not contain georeferencing of its elements, it is not plotted in Figure 3.8. However, Figure 3.10 presents a simplified version of the single line diagram of this network . Figure 3.10 also provides the illustration of the FSPs considered in this case study. In order to incorporate this network into the transmission network, the external grid seen in the picture connected to the substation "Pinar del Rey" becomes the node T5 depicted in Figure 3.8. The line connecting the 66 kV busbar of the substation "Puerto de la Cruz" to the node in which the wind farm PESUR is connected is considered open for the purposes of this study, in line with the actual operation in the demonstration (Chaves-Ávila et al., 2020).

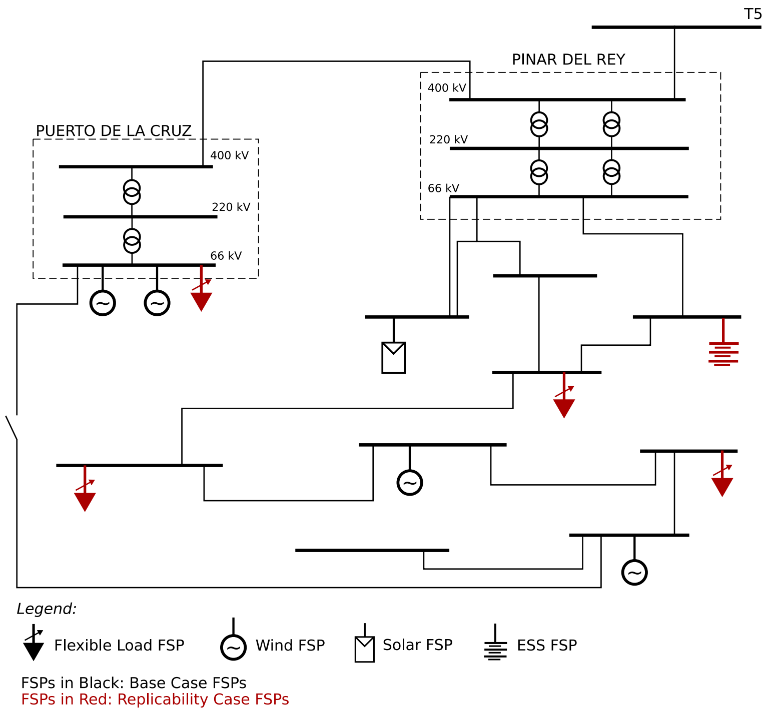

Figure 3.10: Cádiz network. Based on: Ivanova et al. (2022).

[7]The network information used in the section was provided by the DSO under a non disclosure agreement, reason why only public information is displayed in this Thesis. That is also the reason why the case study data is not provided for this chapter 3, as opposed to chapter 4 that does provide case study data in the Appendixes.

Generation and Demand

Similarly to the Swedish case study, eight representative days are created for the demand using the k-means clustering technique, two for each season[8], as shown in Figure 24. Profiles for wind and solar generation are also created based on 2020 data.

The volume of the demand and generation at the transmission grid, however, had to be scaled up from the original data set from the openTEPES, as this data set considers values one order of magnitude lower than the actual figures from the Spanish system.

Once the demand and the installed capacity are calibrated according to the actual figures from 2020, the results for the DA market are analysed in terms of the energy mix and average price per MWh. As shown in Table 3.7, and when compared to the actual generation mix in Figure 3.12, the values obtained are representative of the Spanish system.

	Representative Day (Yearly Values - in GWh)								*Total*	*Mix*
	Winter		Spring		Summer		Autumn			
Technology	High	Low	High	Low	High	Low	High	Low		
CCGT	9,026	4,339	5,242	3,264	8,737	3,461	4,826	3,471	42,367	18%
Cogen.	3,323	2,849	2,781	2,806	3,595	2,645	2,713	2,933	23,645	10%
Hydro	4,324	3,706	3,618	4,500	4,677	3,441	3,529	4,500	32,294	13%
Nuclear	6,697	5,740	5,603	6,945	7,243	5,330	5,467	6,970	49,995	21%
Solar	3,406	2,920	2,850	3,545	3,685	2,711	2,781	3,545	25,444	11%
Thermal	3,503	1,127	1,347	0	3,178	1,039	1,545	0	11,739	5%
Wind	7,374	6,320	6,170	7,675	7,975	5,869	6,019	7,675	55,076	23%
Total									240,562	

Table 3.7: DA results from the Spanish case study.

The average price computed by the model is 58.24 €/MWh, which is higher than the average computed in DG Energy - EC (2021), at 40.2 €/MWh (Q4 - 2020).

Imbalances and Congestion Management needs

Imbalances and congestion management were also calibrated for the Spanish case study. For this purpose, a similar approach to the Swedish case study was used. First, balancing needs for 2020 were gathered from the information published by the Spanish TSO Red Eléctrica (Red Eléctrica, 2024). According to their monthly reports, the tertiary reserve energy activated upwards in 2020 totalled 1.7 TWh, while the downward totalled 1.2 TWh. These values were used as reference values and assigned to nodes in proportion to the demand and the DA clearing result.

The congestion management reference volume considered comes from (ACER, 2021). According to this report, the total volume for remedial action in Spain in 2020 was 10.6 TWh at a total cost of 435 M€. In order to reach similar volumes, the transmission network was calibrated in such a way that the volume of congestion management needs would be compatible with the

[8] The original “small Spanish case” from openTEPES does provide data for all 8760h of the year. However, considering the time involved in running the sensitivities, it was chosen to use the representative day approach for the Spanish case study as well.

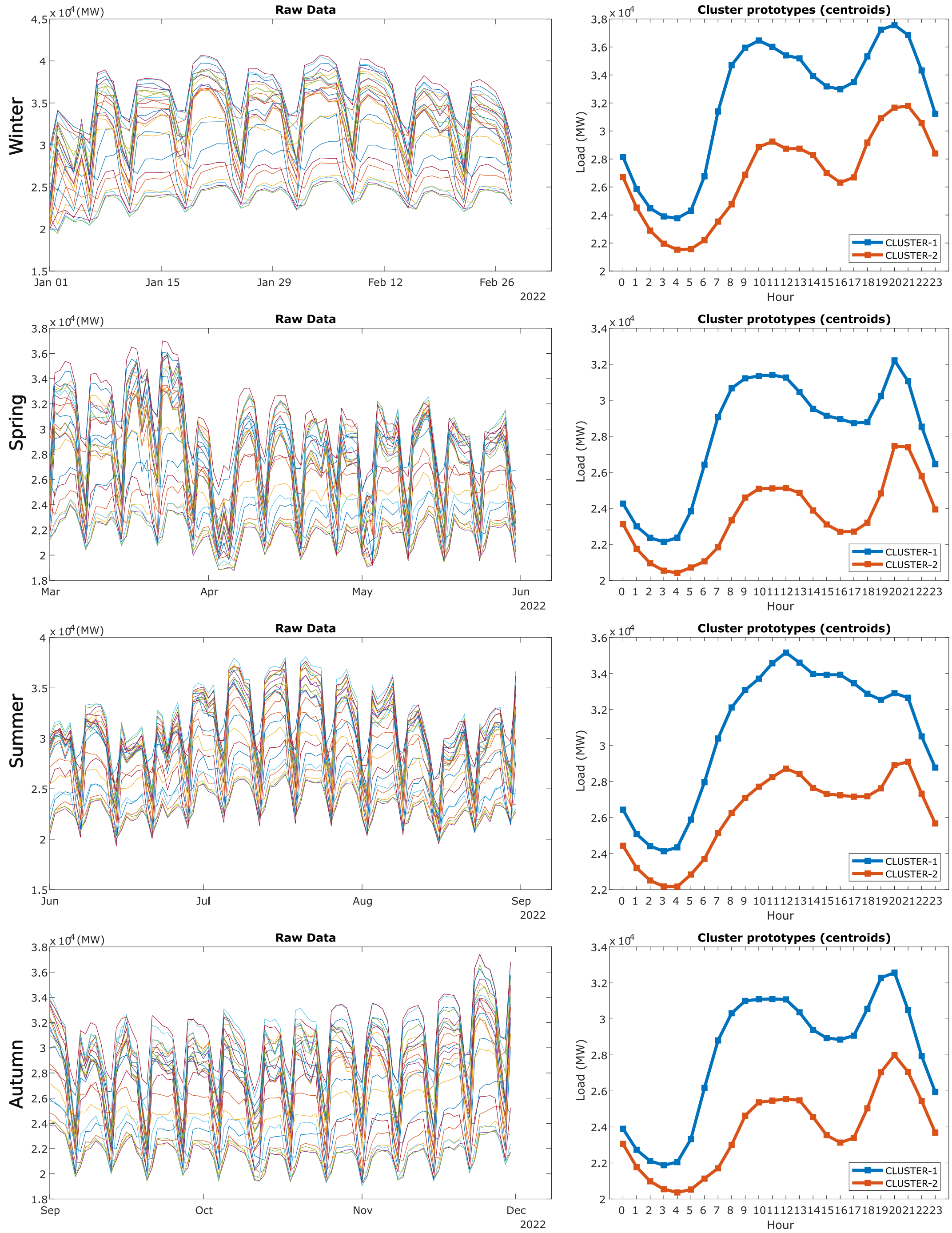

Figure 3.11: Representative days for the Spanish case study.

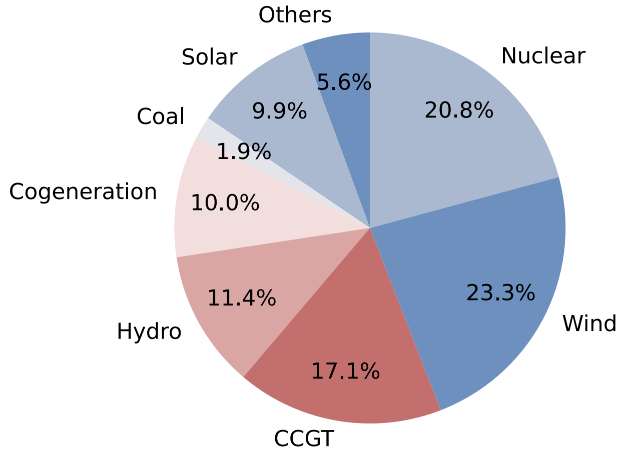

Figure 3.12: Actual generation mix in Spain in 2021. Adapted from: Statista (2022).

reference values obtained from (ACER, 2021). This calibration process was done by scaling up the thermal limits of the transmission lines up to the point where volumes are compatible. The scaling-up process was necessary considering that the original openTEPES network was also dimensioned one order of magnitude lower compared to the actual Spanish values.

3.4.1 Scenarios

FSP identification	Grid	FSP type	Installed Capacity	Downward capacity	Upward Capacity	Bid price (in €/MWh)
WindALB1	Albacete 1	Wind	38	100% of the DA	5% of DA	1
WindALB2	Albacete 1	Wind	49.5	100% of the DA	5% of DA	1
WindALB3	Albacete 1	Wind	13.2	100% of the DA	5% of DA	0.99
WindALB4	Albacete 1	Wind	37	100% of the DA	5% of DA	1.02
WindALB5	Albacete 1	Wind	23	100% of the DA	5% of DA	1.02
WindALB6	Albacete 1	Wind	24	100% of the DA	5% of DA	0.98
WindALB16	Albacete 2	Wind	49.5	100% of the DA	5% of DA	0.99
WindALB17	Albacete 2	Wind	45.5	100% of the DA	5% of DA	1.01
Cogen1	Albacete 1	Cogen.	10	2	2	39.9
WindCAD2	Cadiz 2	Wind	32	100% of the DA	5% of DA	0.98
WindCAD1	Cadiz 2	Wind	10.68	100% of the DA	5% of DA	1.01
SolarCAD1	Cadiz 1	Solar	12.3	100% of the DA	0	1
WindCAD3	Cadiz 1	Wind	42	100% of the DA	5% of DA	1.01
WindCAD4	Cadiz 1	Wind	6	100% of the DA	5% of DA	1.02

Table 3.8: FSP characteristics for the Spanish case study.

The sensitivity scenarios considered are the same as those used for the Swedish demonstration and are presented in Table 3.3. With regard to the replicability analysis, a similar approach to the one in the Swedish case was used. First, the results from the different CSs serve as one replication scenario. Second, a scenario in which FSPs types from the Swedish demonstration are brought to the Spanish context is built. This second replication scenario consists of DR and storage types of FSPs being deployed in both Cádiz and Albacete networks. In addition, a third scenario is tested, considering congestions in selected elements of the grid. Figure 3.10 illustrates the allocation of the Swedish types of FSPs on the Cádiz network.

3.4.2 Results

Table 3.9 presents the energy activated for the Spanish base case. In total, the Spanish TSO activates approximately 8.9 TWh, from which 3.5 TWh are for balancing, and 5.4 TWh are for congestion management purposes. The results also show that congestion management needs are mostly concentrated in the winter months.

Product / Direction	Winter		Spring		Summer		Autumn		Total Year
	High	Low	High	Low	High	Low	High	Low	
Balancing	*395*	*463*	*316*	*563*	*554*	*383*	*364*	*459*	*3,497*
Down.	209	174	161	160	199	164	181	245	1,493
Up.	186	289	155	402	355	219	183	214	2,004
C.M.	*4,967*	*73*	*154*	*9*	*51*	*49*	*104*	*37*	*5,444*
Down.	2,484	36	77	4	25	24	52	18	2,722
Up.	2,484	36	77	4	25	24	52	18	2,722
Total (Bal.+C.M.)	5,363	536	470	571	605	432	468	496	8,941

Table 3.9: Base case scenario for Spanish case study: Energy activated. In GWh/year.

Table 3.10 presents the total cost data for the base case (Common CS) and the other CSs modelled under this study. The results from the multi-level CS implementations reveal that the distribution network is not constrained in the base case scenario.

Market Model	Winter		Spring		Autumn		Summer		Yearly Cost
	High	*Low*	*High*	*Low*	*High*	*Low*	*High*	*Low*	
Common									
Joint	152,255	3,123	4,810	2,515	3,498	1,944	3,152	1,472	172,770
Separate	152,577	3,063	4,896	2,522	3,448	1,886	3,192	1,412	172,997
Multi-level (OPF)									
Local	0	0	0	0	0	0	0	0	0
Joint	152,262	3,124	4,811	2,516	3,498	1,945	3,154	1,473	172,783
Separate	152,584	3,065	4,897	2,522	3,448	1,886	3,193	1,413	173,009
Multi-level (PTDF)									
Local	0	0	0	0	0	0	0	0	0
Joint	152,262	3,124	4,811	2,516	3,498	1,945	3,154	1,473	172,783
Separate	152,584	3,065	4,897	2,522	3,448	1,886	3,193	1,413	173,009

Table 3.10: Objective value for different CSs. Spanish case study. In k€/year.

The first scalability scenario to be simulated is the one with sensitivities over the size of FSPs and the bids offered by the FSPs. Results are presented in the chart in Figure 3.13. In this case, however, the increase in the size of the FSPs actually leads to an increase in the overall system cost. This happens because the FSPs considered in this case study are mostly wind farms. Therefore, increasing the size of FSPs also means increasing the penetration of RES and its generation in the DA. After the sensitivity factor 2 for the size of FSPs, the increased RES generation leads to the need for additional redispatch measures, increasing the overall cost.

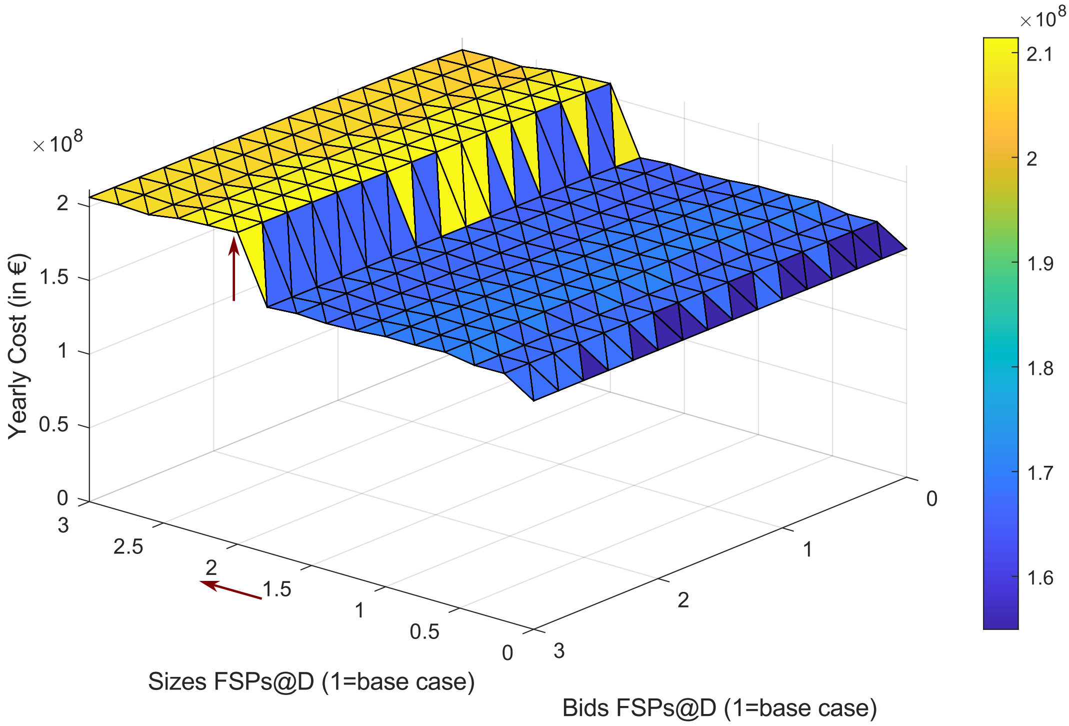

Figure 3.13: Sensitivities over size and bids of FSPs@D. TSO costs in the Common-Joint CS in the Spanish case study.

Figure 3.14 presents the results for the second scalability scenario, in which sensitivity factors are applied to the demand connected to the distribution grids and the sizes of FSPs. These results are only for the LFM portion of the multi-level CS. For this scalability scenario, results are similar to the Swedish case study, although the flat area is much more reduced. This shows that the FSPs originally considered in the Spanish case study have a limited capability to cope or support an increase in demand. That is explained by the fact that the FSPs are mostly RESs such as wind and PV, with little or no upward flexibility capacity.

Finally, Table 3.11 presents the results of the replication scenario of the Spanish case study. In this scenario, two aspects are analysed. First, the Swedish types of FSPs are incorporated in the analysis. Both DR and batteries are considered in the grid of Cádiz and Albacete. Second, congestion is simulated in two different elements of the grids. One congestion in the line between nodes D1006 and D1007 at the Albacete grid, and one congestion in the substation Pinar del Rey. Table 3.11 presents the results of this replication scenario. The most relevant finding from this scenario is the fact that, in the base case, when congestions are simulated, the existing resources are not capable of solving the congestions. This happens because the congestion creates a need for upward

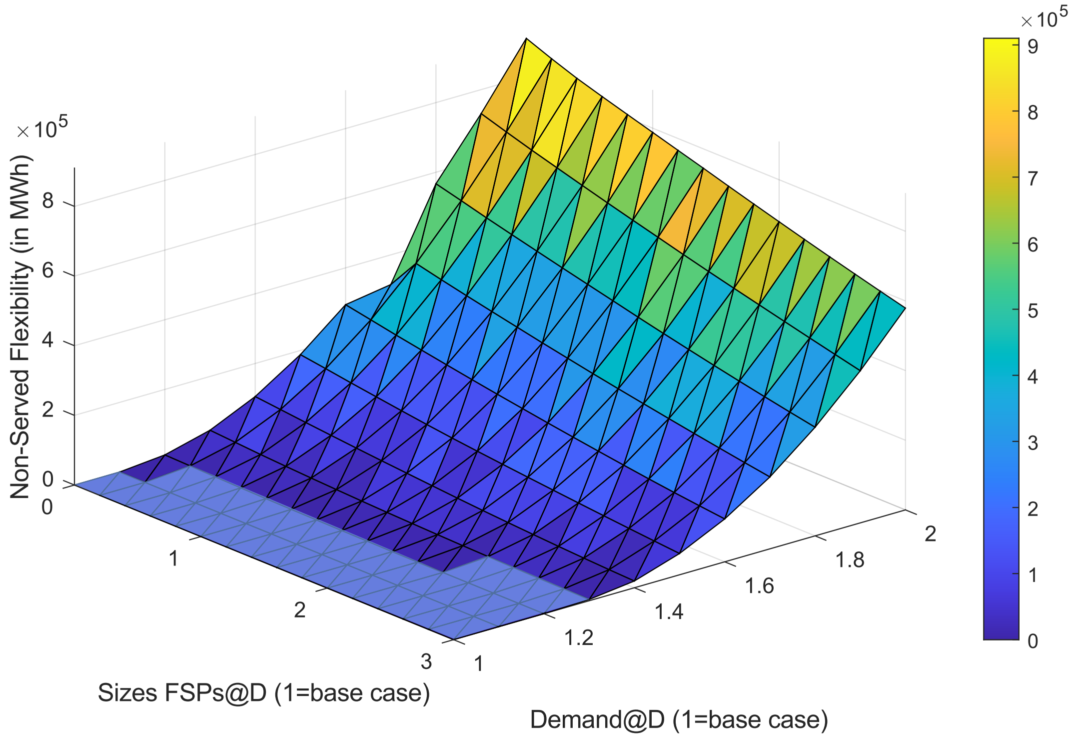

Figure 3.14: Sensitivity of demand at distribution and size of FSPs@D. Non-Supplied Flexibility for DSO in Multi-level (OPF) LFM in ES.

flexibility in the Cádiz network. As wind farms cannot provide the necessary upward flexibility, the DSO enters the NSF state. In the replication scenario, including the resources from the Swedish case study, the congestions created can be solved without NSF for the DSO. With regards to the differences between coordination schemes, no significant difference in total cost is observed, as the Multi-level (in both OPF and PTDF market designs) are close to the Common. The results from the Multi-level CS are in fact slight lower than the Common CS. However, the difference of 0.13% is within the MILP optimality gap of 1% used in this case study. Therefore, this difference is not significant either to conclude that the Multi-level can be cheaper than the Common CS, and for this reasons, the total cost results for the Spanish case studies as considered equivalent.

Market Model	Base Case		Replication Scenario	
	No Cong.	With Cong.	No Cong.	With Cong.
Common				
Joint	169,271	NSF	168,993	170,546
Separate	169,493	NSF	169,223	170,242
Multi-level (OPF)				
Local	0	NSF	0	258
Joint	169,284	170,208	169,005	170,061
Separate	169,505	169,871	169,232	169,736
Multi-level (PTDF)				
Local	0	NSF	0	258
Joint	169,284	170,208	169,005	170,064
Separate	169,505	169,880	169,232	169,747

Table 3.11: Replication Scenarios in the Spanish case study.

From the analysis of the Spanish case study, it can be concluded that diverse grids can be observed in the context of TSO-DSO coordination with HV grids. In the Spanish case study, not only meshed grids with multiple interfaces are seen both in Cádiz and Albacete, but also DSO grids that are exporters of energy, not importers as is generally assumed for distribution grids. In fact, the need for flexibility might also arise in these grids, used almost solely to connect large RESs.

The types of FSPs available for the TSO and DSO play an important role in determining the possibility for SOs to use flexibility. A system dominated by RES type of FSP will be able to provide downward capacity for an extended period but will be limited in providing upward capacity. Therefore, a mix of different types of FSPs could be most beneficial to the SO.

3.5 Conclusions

In this chapter, a techno-economic dispatch model is proposed for the evaluation of different TSO-DSO CSs in the context of balancing and congestion management services being provided by DERs and considering the transmission network and the HV distribution network in a meshed-to-meshed topology. This model is then applied to a realistic case study on the Swedish and Spanish power systems, including the modelling of one year based on real demand and generation data. The use of data clustering and representative days showcases an effective way to model the whole year while keeping computation tractability. This approach could be used by SOs in estimating flexibility needs and for the computation of cost-benefit analyses related to distributed flexibility usage (e.g. grid reinforcement vs distributed flexibility procurement).

In the case of the Swedish case study, the comparison of the different CSs shows that the Common CS leads to the overall least cost of flexibility procurement. In addition, the Multi-level CS with subscription penalties showcased the use of virtual congestions and financial incentives as a way of congestion management cost allocation. Once local flexibility is used at the distribution grid, however, the TSO starts observing a higher cost for congestion management and balancing, as the access to distributed flexibility in a Multi-level CS might be sub-optimal.

The Spanish case study does not present a significant difference between the total cost for the different CSs. This result, however, may be due to the fact that the subtransmission networks considered, as well as their flexibility needs, are small in comparison to the rest of the Spanish system, diluting significant differences in total cost per CS. However, the simulations show that the types of FSPs included in the case study have an important impact on the capabilities for DSOs to solve network problems. Different FSP types will have different capabilities in terms of flexibility provision (e.g. upward or downward, ramping limits etc). This might be seen as an additional risk for SOs (as another dimension to the liquidity risk of distributed flexibility markets). The Spanish case study further highlighted the intertwined effects of increasing DERs that participate in wholesale energy markets and the increase in flexibility available for SOs. While on the Swedish grid, this had a positive effect (i.e., more distributed generation automatically reduced the need for flexibility), on the Spanish case it had the opposite effect: more DG caused further congestions and increased total costs. This indicates that when considering flexibility needs, SOs should follow an integrated approach, one that covers the complete market sequence.

The different variations in the LFM market design are also explored in this chapter. A more complete OPF-base formulation may lead to lower costs, considering the more precise representation of the network. However, the proposed PTDF-based formulation, taking into account only the PTDF over constrained elements of the network (either by thermal limits or subscription penalties) has the advantage of being more transparent to FSPs, as they would know more easily the impact of their flexibility over the congestion being solved by the LFM. Therefore, a trade-off between flexibility procurement cost and market transparency and simplicity is posed. This chapter only assesses the static scenario in which FSPs are the same in both market formulations. However, market design may also influence the overall flexibility offered in the LFM. Assuming that an OPF-based formulation can disincentivise local flexibility participation, a PTDF-based solution could lead to better overall economic results. Such analysis of the relationship between market design and incentives for flexibility offerings could be addressed in future research.

From the DSO's perspective, it is shown that, for the Swedish case study, an increase of only 60% over the base case flexibility could already lead to a situation in which the DSO does not incur subscription penalties. Considering that the grid studied was load-driven, the increase in FSPs availability could also be beneficial when coping with the increase in demand. The study suggested that an increase of 10 GWh of activated flexibility per year would allow the incorporation of 145 GWh of demand without leading to an NSF situation for the DSO. The replication scenario in which wind farms are incorporated into the distribution grid shows that this type of DER could help the DSO to mitigate the surpassing of subscription levels, as the incorporation of distributed generation offsets the need for imports from the TSO through the TSO-DSO interfaces. As for the Spanish case study, similar results in terms of demand absorption by the increase of flexibility is observed, however, to a lower extent. This is due to the fact that FSPs in the Spanish case study were mostly DG, with little or no upward flexibility capability, the type needed for demand increase absorption.

4 A Bilevel Study on Interface Flow Pricing[1]

In this chapter, a bilevel model is proposed, considering a TSO-leader which sets interface prices freely, and DSO-followers in a Stackelberg game. This allows for the identification of regulatory risks and the testing of regulatory mechanisms. Based on two case studies, results show that an incentive-driven TSO acts so that the most economical flexibility providers are activated when compared to the first-best option, namely a Common TSO-DSO flexibility market. If left unregulated, however, it might also create important distortions in cost allocation. Leveraging on these results, a cap and floor mechanism is proposed, showcasing that a Fragmented Coordination Scheme (CS) with dedicated incentives for the TSO could be an efficient second-best when compared to the Common CS and other regulatory options found in the literature.

4.1 Introduction

As identified in chapter 2 and confirmed quantitatively in chapter 3, different CSs yield different performances in terms of flexibility activation costs. It is shown that a Common CS leads to the least cost of procurement when compared to the typical implementations of the Multi-level and the Fragmented CSs. In addition to the theoretical and numerical results showing this point, this characteristic of the Common CS is also intuitive: one single optimisation model, considering all constraints simultaneously leads to the system's optimal solution. In the case of the Multi-level or Fragmented in their typical or "vanilla" form, this is not the case. A Multi-level with bid forwarding in which the DSO runs first their LFM is agnostic of the rest of the system (i.e., TSO and other DSOs) in this first stage, which might potentially condition the global results to a sub-optimal condition. Conversely, the bid validation process when forwarding bids can further introduce losses of efficiency.

[1]This chapter was submitted to the International Journal of Electrical Power & Energy Systems journal and was under peer review until the conclusion of this Thesis.

The Fragmented CS is typically characterised by only allowing SOs to procure flexibility from providers connected to their own networks and obliging them to maintain the forecasted interface flow prior to flexibility markets (Delnooz et al., 2019). In this setting, it is also intuitive why losses of efficiency are introduced, as SOs are limited to the use of flexibility providers withing their network boundaries, potentially blocking the procurement of more efficient providers in other networks which would otherwise available. Therefore, the Fragmented CS is efficient and simple in ensuring a technical feasibility of flexibility markets (i.e., no need for complex validations as the Multi-level), but introduces economic inefficiencies.

An important source of inefficiencies in disjoint CSs (e.g. Multi-level, Fragmented) is the rebalancing problem. When a DSO has a congestion to solve (e.g. overload), it will most probably procure upward flexibility downstream of the congested element (assuming a radial topology). From a system perspective, this activation leads to an imbalance with respect to original dispatch (e.g. wholesale market results). In a typical Multi-level CS, the DSO may not have an incentive to carry further activation (e.g. downward flexibility upstream of the congested element) to rebalance the system. In a Fragmented CS in which schedule power flow over the interface has to be maintained, on the other hand, the DSO has the obligation to rebalance the system no matter the cost. These two extremes bring inefficiencies, as the most efficient solution may lay in between (e.g. some rebalance activations taking place at the transmission grid and some at the distribution). Moreover, not only does an efficiency detriment arise with respect to a Common CS, but also a cost-allocation issue (e.g. in a Multi-level, the TSO pays to rebalance the system due to a congestion in the distribution network).

Therefore, being the Common CS the most efficient from a flexibility procurement cost perspective, it seems clear that this CS has the advantage over the others. However, from an implementation point of view, the Common CS faces many challenges as also indicated in chapter 2, namely the exchange of large amounts of data (which might be private to the individual SO and customers), and difficulties in the market design and market clearing algorithm due to the large size of problems and heterogeneity of needs by SOs. In the literature, several authors propose the use of decomposition techniques to eliminate one of the main difficulties faced by the Common CS, namely, the exchange of private data. By breaking the optimisation problem in pieces that coincide with the networks operated by the individual SOs, the problem of data exchange is possibly eliminated, as only one coupling variable or constraint is exchanged until convergence is reached. In fact, the appendix B of this thesis offers a demonstration of how the Benders decomposition technique can be used to solve a Common CS. The same use cases used in the remainder of this chapter 4 are used for ease of comparison. However, even considering decomposition techniques, implementation of the Common CS is still complex. As shown in chapter 2, the exchange of the coupling variables/constraints data in a synchronised and close to real-time way is challenging and taxing on ICT system.

In this context of sub-optimal Fragmented and Multi-level CSs and a hard-to-implement Common CS, Marques et al. (2023) argue that the economic efficiency of the Multi-Level and Fragmented CSs can be improved if the variation in the power flow over the interfacing substation is priced properly. In fact, it is proven that if the variation over the power flow is priced optimally, the Multi-level and Fragmented CSs can lead to the same result as the Common CS. In order to compute the interface power flow price, first the authors compute a "virtual" Common CS, and then the Multi-level. Although illustrative, this method is not practical. Therefore, the same authors propose the implementation of a bilevel model with decomposition of the optimisation problem. This allows for the practical implementation of the Multi-level CS in which both SOs have independent markets. Nevertheless, this leads to the same challenges as the distributed Common CS implementation, namely, (i) both markets have to be cleared simultaneously (so the convergence of prices at the interface can be achieved), and (ii) the ICT requirements are higher, as the near real-time information exchange has to take place.

Therefore, this chapter proposes a continuation to the studies on the performance and applicability of interface flow pricing. Instead of algorithmically finding the optimal interface flow prices, this chapter considers first a situation in which a TSO could set the interface price freely, independent from a "virtual Common CS run" or a decomposed TSO-DSO architecture. It is also assumed that the TSO can act strategically, which might not be entirely realistic, considering that the TSO is a regulated company (Pérez-Arriaga, 2014). However, it allows the research on incentives and regulatory risks, as well as to proposition and testing of eventual regulation.

In the context of conflicting interests between the TSO and DSO, game theory can help identify the dynamics created by each rational player trying to maximise their payoff in anticipation of the actions of other player. Xie et al. (2022), for instance, propose TSO-DSO Nash equilibrium model in the context of wholesale energy trading. Sheikhahmadi et al. (2021) propose a bilevel TSO-DSO model also for wholesale energy markets. Chen et al. (2021a) more specifically study the clearing of a local integrated heat and electricity market and a TSO-operated wholesale energy market in a bilevel formulation. These studies, however, focus mostly on coordination for wholesale energy trading, something less applicable in the European context.

In this chapter, a bilevel optimisation model is introduced, modelling a Stackelberg game in which the TSO sets the interface price first, followed by the DSO's LFM and the TSO Congestion Management markets in a Fragmented CS. The objective of the present study is two-fold. On the one hand, it points out scenarios in which regulatory supervision might be important, considering the asymmetry of information that might exist between a TSO setting interface prices and the regulator. On the other hand, the bilevel model proposed offers an opportunity to test different regulatory mechanisms such as interface price caps and floors, limiting the potential for strategic behaviour by the TSO and offering a quantifiable and implementable second-best to the Common CS.

Two key aspects are analysed when gauging the efficiency of regulatory options. On the one hand, the total cost of procuring flexibility is compared to the Common CS, which leads, by definition, to the least total cost (Marques et al., 2023). On the other hand, the cost allocation between TSO and DSO is analysed, comparing it with the Fragmented with optimal interface flow pricing.

Therefore, the main contributions of this chapter are:

- The development of a novel bilevel optimisation model to study the behaviours at pricing the TSO-DSO interface.
- The identification of regulatory risks in interface-pricing practice.
- The testing of regulatory mechanisms for efficient limitation of strategic behaviour and comparable efficiency and cost allocation with respect to the Common CS and the Fragmented CS optimally priced, respectively.

The remainder of the chapter is structured as follows. Section 4.2 describes the methodology and presents the optimisation models proposed and section 4.3 presents the case studies used in this chapter and their results. Section 4.4 discusses the policy and regulatory implications. Finally, section 4.5 concludes.

4.2 Assumptions and Methodology

In this chapter, we analyse flexibility markets for both the TSO and DSO in a Fragmented CS fashion. This means that the TSO and DSO can use resources connected to their grids only to solve congestions in the network. Congestions are here considered primarily overloads of the network elements. The choice for considering only the Fragmented CS and the product service congestion management is to keep the model and analysis tractable. It is also a typical CS in the academic and as well as real-world implementations (Troncia et al., 2023). A Common CS implementation, however, is also modelled and used to provide a baseline for optimal flexibility procurement. Additionally, the analysis could be easily expanded to include other disjoint CSs, such as the Multi-level, in which unused bids by the DSO are forwarded to the TSO. In fact, Marques et al. (2023) show that the optimal pricing of the substation leads to optimal flexibility procurement in both the Fragmented and Multi-level CSs. In this case, and considering a Fragmented CSs, the power flow over the interface substation could be altered by the DSO at the cost (or revenue) of the interface flow price.

The market sequence modelled in this chapter aims to represent a typical European market structure. Wholesale energy markets determine the nominations without considering network constraints [2]. The results of the wholesale energy markets are then passed on to the TSO for feasibility and security verification (Meeus, 2020). Considering the future existence of LFMs, we assume that DSOs will use LFMs in a similar way that TSO today check for network feasibility and apply remedial actions. TSOs in Europe may use several mechanisms to solve internal congestions, such as mandatory redispatch, counter trading or organised congestion management markets (EU, 2015). In this chapter, we focus on the latter, as implemented in Spain (CNMC, 2022).

In order to keep the analysis tractable, we only consider the procurement of flexibility in terms of active power. As a result, congestions are limited to overloads in this chapter. Voltage violations and respective services are not considered in this research considering that additional market algorithms could be required, such as reactive power markets (Davi-Arderius et al., 2023). However, if voltage violations are solved by the use of active power alone, all developments and conclusions of this chapter still hold true. At lower voltage levels, the higher resistance over reactance rate (R/X) and network radiality allow for voltage regulation approaches to exploit the monotonic decreasing of voltage magnitude along the feeders (Alizadeh et al., 2016). Therefore, at lower voltage grids, voltage control can be based on active power flows (Davi-Arderius et al., 2023).

Following the Congestion Management markets, balancing markets would take place in a typical European market sequence (Meeus, 2020). These markets, however, are omitted from the

[2] In Europe, cross-bidding zone congestions are considered, but not intra-bidding zones. For the sake of simplicity, only one TSO is considered, which in most European countries is limited to solving congestion in a single bidding zone.

model in this chatper, as is the wholesale energy market. An implementation of the full market sequence including a Day-ahead, congestion management and balancing services in several TSO-DSO CSs can be seen in Lind et al. (2023).

4.2.1 Sequential optimisation

The Fragmented CS with interface flow pricing, in this sequential form, is characterised by an LFM run by the DSO followed by a congestion management market run by the TSO. After the LFM, the DSO informs of possible changes in the interface power flow with respect to the original schedule and pays the TSO for the difference in the power flow at the substation, as this difference will have to be rebalanced by the TSO. Different ways of setting this substation price are discussed in the following sections.

DSO's Local Flexibility Market

The LFM formulation in its sequential single-level form is presented in (4.1). In this model, the DSO minimises their flexibility procurement cost plus the cost for the change in the substation power flow in (4.1a). Nodal power balance equations for both active and reactive power are presented in (4.1b) and (4.1e), respectively. Eq. (4.1c) computes the final active power flow at the TSO-DSO interfacing substation. Reactive power demand is assumed to be based on a fixed power factor, calculated in (4.1h). The reactive power flow over the interfacing substation is given by (4.1f). Eq. (4.1g) computes active and reactive power flows as well as the square of voltages w_i, while (4.1d) sets the reference bus.

For the computation of power flows, the choice of an AC OPF relaxation is needed (Bobo et al., 2021). Therefore, the constraint (4.1g) is based on a *LinDistFlow* OPF (Baran and Wu, 1989). The *LinDistFlow* is a lossless linear power flow formulation for radial networks capable of accounting for both active and reactive power as well as voltage magnitudes, providing a more precise representation of distribution networks when compared with a DC OPF while maintaining the flexibility of a linear program. Linearity is a desirable feature in this model as it will be later converted in the Karush–Kuhn–Tucker (KKT) conditions. For this reason, the more precise *DistFlow* algorithm is not used.

Moreover, being an OPF-based market algorithm, this formulation also provides Distribution Locational Marginal Prices (DLMPs), given by the dual variable $\lambda_{i,s}^{D1}$ of the power balance constraint (4.1b). The LFM formulation in this chapter is similar to the one proposed in Sanjab et al. (2021).

Eq. (4.1i)-(4.1r) set the upper and lower limits for up and downward flexibility activation, active and reactive power flow, and voltage magnitudes.

$$\min \sum_{s\in S^D, k\in K^{DSO}} \left[\left(Bid_k^{up}\cdot p_k^{up}\right) + \left(Bid_k^{dw}\cdot p_k^{dw}\right)\right] + \sum_{s\in S^D, k\in K^{DSO}} (p_k^{up} - p_k^{dw})\cdot IntPrice_s \tag{4.1a}$$

s.t.

$$DispatchDA_i + \sum_{k \in IF} p_k^{up} - \sum_{k \in IF} p_k^{dw} - \sum_j f_{i,j}^p + \sum_j f_{j,i}^p - D_i^p = 0 \\ : \lambda_{i,s}^{D1} \quad \forall i \in I^{DSO}, s \in S^D \tag{4.1b}$$

$$f_{i,j \in I^{SUBS}}^p + DaDSO_s - \sum_{s \in S^D, i, k} (p_k^{up} - p_k^{dw}) = 0 \\ : \lambda_{i,j,s}^{D2} \quad \forall (i,j) \in L, i \in IS, s \in S^D \tag{4.1c}$$

$$w_i - 1 = 0 \quad : \lambda_{s,i}^{D3} \quad \forall s \in S^D, i \in SLACK^s \tag{4.1d}$$

$$+ \sum_{k \in IF} q_k - \sum_j f_{i,j}^q + \sum_j f_{j,i}^q - D_i^q = 0 \\ : \lambda_{i,s}^{D4} \quad \forall i \in IS, s \in S^D \tag{4.1e}$$

$$f_{i,j}^q - slackQ_{i,j} = 0 \quad : \lambda_{i,j,s}^{D5} \quad \forall (i,j) \in L, i \in IS, j \in I^{SUBS}, s \in S^D \tag{4.1f}$$

$$w_i - w_j - 2 \cdot (R_{i,j} \cdot f_{i,j}^p + X_{i,j} \cdot f_{i,j}^q) = 0 \quad : \lambda_{i,j,s}^{D6} \quad \forall (i,j) \in L, i \in IS, s \in S^D \tag{4.1g}$$

$$q_k - \tan(\arccos(PF)) * (p_k^{up} - p_k^{dw}) = 0 \quad : \lambda_{k,i,s}^{D7} \quad \forall k \in K^{DSO} \tag{4.1h}$$

$$p_k^{up} - P_k^+ \leq 0 \quad : \bar{\mu}_k^{up} \quad \forall k \in K^{DSO} \tag{4.1i}$$

$$-p_k^{up} \leq 0 \quad : \underline{\mu}_k^{up} \quad \forall k \in K^{DSO} \tag{4.1j}$$

$$p_k^{dw} - P_k^- \leq 0 \quad : \bar{\mu}_k^{dw} \quad \forall k \in K^{DSO} \tag{4.1k}$$

$$-p_k^{dw} \leq 0 \quad : \underline{\mu}_k^{dw} \quad \forall k \in K^{DSO} \tag{4.1l}$$

$$f_{i,j}^p - F_{i,j}^{p,+} \leq 0 \quad : \bar{\mu}_{i,j}^p \quad \forall (i,j) \in L, i \in I^{DSO} \tag{4.1m}$$

$$F_{i,j}^{p,-} - f_{i,j}^p \leq 0 \quad : \underline{\mu}_{i,j}^p \quad \forall (i,j) \in L, i \in I^{DSO} \tag{4.1n}$$

$$f^q_{i,j} - F^{q,+}_{i,j} \leq 0 \quad : \bar{\mu}^q_{i,j} \quad \forall (i,j) \in L, i \in I^{DSO} \tag{4.1o}$$

$$F^{q,-}_{i,j} - f^q_{i,j} \leq 0 \quad : \underline{\mu}^q_{i,j} \quad \forall (i,j) \in L, i \in I^{DSO} \tag{4.1p}$$

$$w_i - (V^+)^2 \leq 0 \quad : \bar{\mu}^V_i \quad \forall i \in I^{DSO+} \tag{4.1q}$$

$$(V^-)^2 - w_i \leq 0 \quad : \underline{\mu}^V_i \quad \forall i \in I^{DSO+} \tag{4.1r}$$

TSO's Congestion Management

The TSO's congestion management model is a redispatch market based on a DC OPF. The DC OPF formulation is chosen given the meshed topology and low estimation error for the voltage levels at the transmission grid, considering the high X/R ratio (Purchala et al., 2005). The TSO's objective function consists of minimising flexibility activation at the transmission grid minus the transfers received from the DSOs for imbalances after their LFMs (4.2a). Equations (4.2b) and (4.2c) calculate the active power flow to be delivered by the TSO at the interfacing substation considering the summation of nodal demands D^p_i, generation $DispatchDA_i$ and flexibility activations from the LFMs $p^{up,*}_k$ and $p^{dw,*}_k$. The nodal power balance constraint and the DC OPF restrictions are included in (4.2d)-(4.2f). Locational marginal prices are given by the dual variable $\lambda^{T3}_{i,s}$. Eq. (4.2g)-(4.2n) set the upper and lower limits for upward and downward flexibility activation, active power flow, and voltage angles.

$$\begin{aligned} \min \sum_{s \in S^T, k \in K^{TSO}} & \left[\left(Bid^{up}_k \cdot p^{up}_k \right) + \left(Bid^{dw}_k \cdot p^{dw}_k \right) \right] \\ & - \sum_{s \in S^D, k \in K^{DSO}} (p^{up,*}_k - p^{dw,*}_k) \cdot IntPrice_s \end{aligned} \tag{4.2a}$$

s.t.

$$\begin{aligned} f^p_{i,j} - DSOdemand_{s'} = 0 \quad : \lambda^{T1}_{i,j,s,s'} \quad \forall (i,j) \in L, \\ i \in I^{TSO}, j \in I^{SUBS}, s \in S^T, (s,j,s') \in INTER \end{aligned} \tag{4.2b}$$

$$\begin{aligned} - \sum_{i \in I^{DSO}} DispatchDA_i - \sum_{k \in K^{DSO}} p^{up,*}_k + \sum_{k \in K^{DSO}} p^{dw,*}_k + \sum_{i \in I^{DSO}} D^p_i \\ - DSOdemand_s = 0 \quad : \lambda^{T2}_s \quad \forall s \in S^D \end{aligned} \tag{4.2c}$$

$$DispatchDA_i + \sum_{k \in IF} p_k^{up} - \sum_{k \in IF} p_k^{dw} - \sum_j f_{i,j}^p + \sum_j f_{j,i}^p - D_i^p = 0 \quad : \lambda_{i,s}^{T3} \quad \forall i \in IS, s \in S^T \tag{4.2d}$$

$$f_{i,j} - SB \cdot \frac{\theta_i - \theta_j}{X_{i,j}} = 0 \quad : \lambda_{i,j,s}^{T4} \quad \forall (i,j) \in L, i \in I^{TSO}, s \in S^T \tag{4.2e}$$

$$\theta_i = 0 \quad : \lambda_{s,i}^{T5} \quad \forall s \in S^T, i \in SLACK^s \tag{4.2f}$$

$$p_k^{up} - P_k^+ \leq 0 \quad : \bar{\mu}_k^{up} \quad \forall k \in K^{TSO} \tag{4.2g}$$

$$-p_k^{up} \leq 0 \quad : \underline{\mu}_k^{up} \quad \forall k \in K^{TSO} \tag{4.2h}$$

$$p_k^{dw} - P_k^- \leq 0 \quad : \bar{\mu}_k^{dw} \quad \forall k \in K^{TSO} \tag{4.2i}$$

$$-p_k^{dw} \leq 0 \quad : \underline{\mu}_k^{dw} \quad \forall k \in K^{TSO} \tag{4.2j}$$

$$f_{i,j}^p - F_{i,j}^{p,+} \leq 0 \quad : \bar{\mu}_{i,j}^p \quad \forall (i,j) \in L, i \in I^{TSO} \tag{4.2k}$$

$$F_{i,j}^{p,-} - f_{i,j}^p \leq 0 \quad : \underline{\mu}_{i,j}^p \quad \forall (i,j) \in L, i \in I^{TSO} \tag{4.2l}$$

$$\theta_i - \theta^+ \leq 0 \quad : \bar{\mu}_i^\theta \quad \forall i \in I^{TSO+} \tag{4.2m}$$

$$\theta^- - \theta_i \leq 0 \quad : \underline{\mu}_i^\theta \quad \forall i \in I^{TSO+} \tag{4.2n}$$

4.2.2 Bilevel model

In order to evaluate the potential strategic behaviours of interface price setting and applicable policies, a bilevel model is derived from the single-level linear programs above. A bilevel model can represent a Stackelberg game, in which a leader (upper level) plays first announcing his strategy, followed by a follower that reacts to the leader's first move (Fortuny-Amat and McCarl, 1981). In the proposed model, the TSO sets the interface price first. The choice for the TSO to be the interface price setter is not arbitrary. First, the TSO is the SO that has visibility over all the interfaces with DSOs and, therefore, is the actor with more information to gauge a systemic cost of rebalancing. Second, it is sensible to assume that the TSO publishes the interface prices first so that DSOs have transparency to choose between rebalancing their LFMs or paying the imbalances to the TSO. A similar mechanism is in place in Sweden, in which the TSO sets the price for surpassing a virtual power flow limit at the interface, called subscription cost (Ruwaida et al., 2023).

Therefore, in this bilevel implementation, we assume the TSO moves first by setting the price for the change of interface flows. According to this game-theoretical approach, the TSO will set the interface price in anticipation of what the reactions of DSOs will be. This, of course, assumes that the TSO has perfect information over DSOs' market, which is not expected to be the case. Nevertheless, considering that we model a one-shot game, the assumption of perfect information can be seen as the result of a repetitive game in which the TSO learns the characteristics of the DSOs' markets, considering that LFMs are expected to be relatively stable and predictable.

Figure 4.1 illustrates the overall structure of the bilevel model proposed. The upper level determines the interface prices, which are then passed on to the DSOs at the lower level. After the LFM, the TSO solves the final congestion management market. While the interface prices are sent from the upper level to the DSO's lower level, the quantity imbalanced is passed from the lower level to the upper level. Similarly, the DSO's lower level informs the flexibility activated for the computation of the final substation power flow, as described in single-level implementation. Finally, the lower level of the TSO also shares to the upper level the flexibility activated on the transmission grid. The TSO's congestion management market is modelled as a second lower level to represent the market sequence proposed.

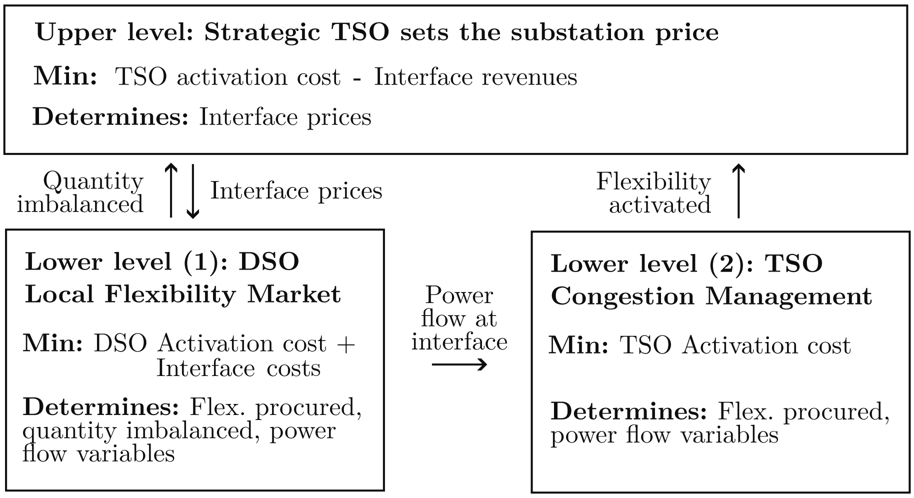

Figure 4.1: TSO-DSO bilevel model structure

While Figure 4.1 highlights the bilevel structure and exchange of variables between models. This type of bilevel formulation containing one upper level and multiple lower levels can be solved as a single optimisation problem by transforming the lower levels into their KKT conditions (Gabriel et al., 2012). In addition, linearisation of complementarity conditions and other bilinear terms may also be required (Beckstedde et al., 2023; Gonzalez-Romero et al., 2021). Following these procedures, the formulations for upper and lower levels presented below are solved as a single MILP, as described below. The model is implemented in GAMS language and its source code is publicly available in Lind et al. (2024b).

Upper level

The upper level's objective function is very similar to (4.2a), in which the TSO minimises the activation cost while having revenues from the interfacing substation.

For the general implementation of this bilevel model, and for the purpose of studying the properties of strategic behaviour, the only restriction for the upper level is a cap for the interface price (4.3b). This cap is a large enough value to avoid having an unbounded problem, and is set at 1,000 €/MWh in the case studies of this chapter. More realistic regulatory mechanisms for limiting or defining the interface prices are presented in section 4.3.4.

The difference with respect to model (4.2) is the interface price $intprice_s$ is the decision variable of the upper level, while it was a parameter at the single level. In addition, the flexibility procurement is passed on from the lower to the upper level.

Moreover, one may notice that the objective function of the upper level contains the bi-linear term $(p_k^{up} - p_k^{dw}) \cdot intprice_s$. This term is linearised by the use of the Strong Duality Theorem (Gabriel et al., 2012; Ruiz and Conejo, 2009). This linearisation procedure is presented in appendix C.1.

$$\begin{aligned} \min \sum_{s\in S^T, k\in K^{TSO}} & \left[\left(Bid_k^{up} \cdot P_k^{up} \right) + \left(Bid_k^{dw} \cdot P_k^{dw} \right) \right] \\ & - \sum_{s\in S^D, k\in K^{DSO}} \left(P_k^{up} - P_k^{dw} \right) \cdot intprice_s \end{aligned} \tag{4.3a}$$

s.t.

$$0 \leq intprice_s \leq IntPrice_s^{+} \tag{4.3b}$$

Lower level: DSO's LFM

The lower level of the DSO's LFM is converted to the KKT conditions, resulting in the set of restrictions presented in (4.4). It is also worth mentioning that the complementarity conditions of the KKTs (4.4i)-(4.4r) are linearised by the employment of the Big-M technique, allowing the final model to be solved as a MILP. This linearisation of the complementarity conditions is presented in appendix C.2.

$$(4.1b), (4.1c), (4.1d), (4.1e), (4.1f), (4.1g), (4.1h), \tag{4.4a}$$

$$\begin{aligned} & Bid_k^{up} + \sum_{s\in S^D} intprice_s + \sum_{i\in I^{DSO}, s\in S^D} \lambda_{i,s}^{D1} + \sum_{i\in I^{DSO}, j, s\in S^D} \lambda_{i,j,s}^{D2} \\ & - \sum_{s\in S^D} \lambda_{k,s}^{D7} \cdot \tan(\arccos(PF)) + \bar{\mu}_k^{up} - \underline{\mu}_k^{up} = 0 \quad \forall k \in K^{DSO} \end{aligned} \tag{4.4b}$$

$$
\begin{aligned}
&Bid_k^{dw} - \sum_{s \in S^D} intprice_s - \sum_{i \in I^{DSO}, s \in S^D} \lambda_{i,s}^{D1} - \sum_{i \in I^{DSO}, j, s \in S^D} \lambda_{i,j,s}^{D2} \\
&+ \sum_{s \in S^D} \lambda_{k,s}^{D7} \cdot \tan(\arccos(PF)) + \bar{\mu}_k^{dw} - \underline{\mu}_k^{dw} = 0 \quad \forall k \in K^{DSO}
\end{aligned}
\tag{4.4c}
$$

$$
\sum_{i, s \in S^D} \lambda_{i,s}^{D4} + \sum_{s \in S^D} \lambda_{k,s}^{D7} + \bar{\mu}_k^{q} - \underline{\mu}_k^{q} = 0 \quad \forall k \in K^{DSO}
\tag{4.4d}
$$

$$
\begin{aligned}
&- \sum_{s \in S^D} \lambda_{i,s}^{D1} + \sum_{s \in S^D} \lambda_{j,s}^{D1} + \sum_{s \in S^D} \lambda_{i,j,s}^{D2} - \sum_{s \in S^D} [2 \cdot \lambda_{i,j,s}^{D6} \cdot R_{i,j}] \\
&\qquad + \bar{\mu}_{i,j}^{p} - \underline{\mu}_{i,j}^{p} = 0 \quad \forall (i,j) \in L, i \in I^{DSO}
\end{aligned}
\tag{4.4e}
$$

$$
\begin{aligned}
&- \sum_{s \in S^D} \lambda_{i,s}^{D4} + \sum_{s \in S^D} \lambda_{j,s}^{D4} + \sum_{s \in S^D} \lambda_{i,j,s}^{D5} - \sum_{s \in S^D} [2 \cdot \lambda_{i,j,s}^{D6} \cdot X_{i,j}] \\
&\qquad + \bar{\mu}_{i,j}^{q} - \underline{\mu}_{i,j}^{q} = 0 \quad \forall (i,j) \in L, i \in I^{DSO}
\end{aligned}
\tag{4.4f}
$$

$$
\begin{aligned}
&+ \sum_{s \in S^D} \lambda_{s, i \in SLACK^s}^{D3} + \sum_{s \in S^D, j} \lambda_{i,j,s}^{D6} - \sum_{s \in S^D, j} \lambda_{j,i,s}^{D6} \\
&\qquad + \bar{\mu}_i^{V} - \underline{\mu}_i^{V} = 0 \quad \forall i \in I^{DSO}
\end{aligned}
\tag{4.4g}
$$

$$
- \sum_{s \in S^D} \lambda_{i,j,s}^{D5} = 0 \quad \forall (i,j) \in L, i \in I^{DSO}, j \in I^{SUBS}
\tag{4.4h}
$$

$$
0 \leq -p_k^{up} + P_k^{+} \perp \bar{\mu}_k^{up} \geq 0 \quad \forall k \in K^{DSO}
\tag{4.4i}
$$

$$
0 \leq p_k^{up} \perp \underline{\mu}_k^{up} \geq 0 \quad \forall k \in K^{DSO}
\tag{4.4j}
$$

$$
0 \leq -p_k^{dw} + P_k^{-} \perp \bar{\mu}_k^{dw} \geq 0 \quad \forall k \in K^{DSO}
\tag{4.4k}
$$

$$
0 \leq p_k^{dw} \perp \underline{\mu}_k^{dw} \geq 0 \quad \forall k \in K^{DSO}
\tag{4.4l}
$$

$$
0 \leq -f_{i,j}^{p} + F_{i,j}^{p,+} \perp \bar{\mu}_{i,j}^{p} \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO}
\tag{4.4m}
$$

$$0 \leq -F_{i,j}^{p,-} + f_{i,j}^{p} \perp \underline{\mu}_{i,j}^{p} \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{4.4n}$$

$$0 \leq -f_{i,j}^{q} + F_{i,j}^{q,+} \perp \bar{\mu}_{i,j}^{q} \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{4.4o}$$

$$0 \leq -F_{i,j}^{q,-} + f_{i,j}^{q} \perp \underline{\mu}_{i,j}^{q} \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{4.4p}$$

$$0 \leq -w_i + (V^{+})^2 \perp \bar{\mu}_{i}^{V} \geq 0 \quad \forall i \in I^{DSO+} \tag{4.4q}$$

$$0 \leq -(V^{-})^2 + w_i \perp \underline{\mu}_{i}^{V} \geq 0 \quad \forall i \in I^{DSO+} \tag{4.4r}$$

Lower level: TSO's Congestion Management

The lower level of the TSO's Congestion Management market is also converted to the KKT conditions presented below. For the final MILP implementation, complementarity conditions are also linearised and presented in appendix C.2.

$$(4.2b), (4.2c), (4.2d), (4.2e), (4.2f), \tag{4.5a}$$

$$Bid_k^{up} + \sum_{i \in I^{TSO}, s \in S^T} \lambda_{i,s}^{T3} + \bar{\mu}_k^{up} - \underline{\mu}_k^{up} = 0 \quad \forall k \in K^{TSO} \tag{4.5b}$$

$$Bid_k^{dw} - \sum_{i \in I^{TSO}, s \in S^T} \lambda_{i,s}^{T3} + \bar{\mu}_k^{dw} - \underline{\mu}_k^{dw} = 0 \quad \forall k \in K^{TSO} \tag{4.5c}$$

$$\begin{aligned} - \sum_{s \in S^T} \lambda_{i,s}^{T3} + \sum_{s \in S^T} \lambda_{j,s}^{T3} + \sum_{s \in S^T, s' \in S^D} \lambda_{i,j,s,s'}^{T1} + \sum_{s \in S^T} \lambda_{i,j,s}^{T4} \\ + \bar{\mu}_{i,j}^{p} - \underline{\mu}_{i,j}^{p} = 0 \quad \forall (i,j) \in L, i \in I^{TSO} \end{aligned} \tag{4.5d}$$

$$\begin{aligned} - \sum_{s \in S^T, j \in L(i,j)} \frac{SB}{X_{i,j}} \cdot \lambda_{i,j,s}^{T4} + \sum_{s \in S^T, j \in L(j,i)} \frac{SB}{X_{j,i}} \cdot \lambda_{j,i,s}^{T4} \\ + \lambda_{s \in S^T, i \in SLACK^s}^{T5} + \bar{\mu}_i^{\theta} - \underline{\mu}_i^{\theta} = 0 \quad \forall i \in I^{TSO+} \end{aligned} \tag{4.5e}$$

$$\sum_{s \in S^T, i \in I^{DSO}, j} \lambda_{i,j,s,s'}^{T1} - \lambda_{s'}^{T2} = 0 \quad \forall s' \in S^D \tag{4.5f}$$

$$0 \leq -p_k^{up} + P_k^{+} \perp \bar{\mu}_k^{up} \geq 0 \quad \forall k \in K^{TSO} \tag{4.5g}$$

$$0 \leq p_k^{up} \perp \underline{\mu}_k^{up} \geq 0 \quad \forall k \in K^{TSO} \tag{4.5h}$$

$$0 \leq -p_k^{dw} + P_k^- \perp \bar{\mu}_k^{dw} \geq 0 \quad \forall k \in K^{TSO} \tag{4.5i}$$

$$0 \leq p_k^{dw} \perp \underline{\mu}_k^{dw} \geq 0 \quad \forall k \in K^{TSO} \tag{4.5j}$$

$$0 \leq -f_{i,j}^p + F_{i,j}^{p,+} \perp \bar{\mu}_{i,j}^p \geq 0 \quad \forall (i,j) \in L, i \in I^{TSO} \tag{4.5k}$$

$$0 \leq -F_{i,j}^{p,-} + f_{i,j}^p \perp \underline{\mu}_{i,j}^p \geq 0 \quad \forall (i,j) \in L, i \in I^{TSO} \tag{4.5l}$$

$$0 \leq -\theta_i + \theta^+ \perp \bar{\mu}_i^\theta \geq 0 \quad \forall i \in I^{TSO+} \tag{4.5m}$$

$$0 \leq -\theta^- + \theta_i \perp \underline{\mu}_i^\theta \geq 0 \quad \forall i \in I^{TSO+} \tag{4.5n}$$

4.3 Case Studies

Two case studies are used in this chapter to apply the proposed formulation and study strategic behaviours in interface price setting. First, a stylised model with 5 buses on the transmission grid and 2 buses on the distribution network is presented. This model is used primarily to highlight the mechanics in the interface price setting. Second, a larger 102-bus case study is formulated. In this case study, four 18-bus distribution grids are connected to a 30-bus transmission grid. In this second case study, more advanced dynamics involving multiple DSOs can be observed.

4.3.1 Stylised Case Study

The transmission grid used in the stylised case study is the PJM 5-bus system (Li and Bo, 2010). Connected to bus T2, an interfacing substation and a 2-bus radial feeder distribution network are connected. Figure 4.1 illustrates the network, indicating that lines T3-T4 and D1002-D1003 are congested. To solve the congestions, the DSO has at its disposal the FSPs 1 to 3, while the TSO has generators connected at buses T3 and T4. The bids offered by each flexibility provider in both upward and downward directions are listed in Table 4.1. Both up and downward bids are positive values and paid by the SOs. This is done considering that the FSPs connected at the distribution grid could be also requesting a payment to increase consumption, as seen in actual LFMs such as Piclo. However, the formulation and case studies presented could also be used in the case of payments by the FSP to the SOs.

From a simple analysis, it is clear that the only FSP capable of solving the congestion at line D1002-D1003 is the FSP 3, which is capable of providing upward and downward flexibility. The TSO, on the other hand, has to redispatch generators at T3 and T4 to solve the congestion at the transmission grid. The remaining flexibility activation is with regard to rebalancing the upward activation of FSP 3. Other 4 MW downward are necessary to rebalance the pre-LFM state. This

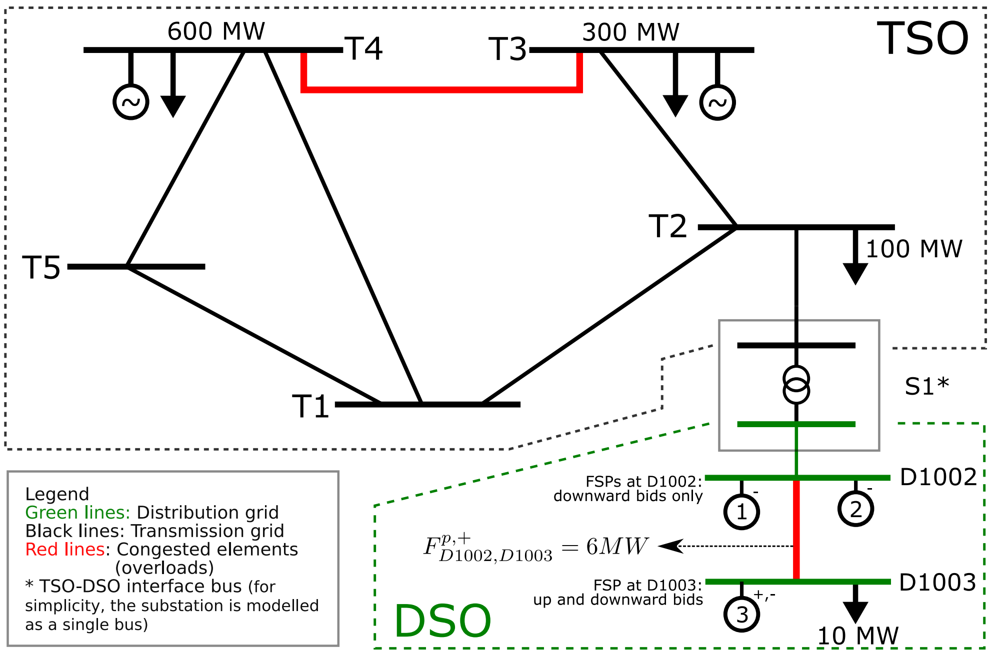

Figure 4.2: Stylised Case Study - Network diagram

FSP	Busbar	Upward bid		Downward Bid	
		MW	€/MWh	MW	€/MWh
G3	T3	500	50	500	50
G4	T4	300	20	300	20
FSP 1	D1002	0	10	2	10
FSP 2	D1002	0	30	2	30
FSP 3	D1003	5	60	5	60

Table 4.1: FSP bids in Stylised Case Study

could be done by either activating FSPs 1 and/or 2 at the distribution grid, or G4, considering network constraints.

The cheapest way to rebalance the system is achieved by the run of a Common CS. This CS indicates that the 2 MW downward should be activated from FSP 1 and the remaining 2 MW as a redispatch between G3 and G4. On a relaxed Fragmented CS in which the interface price $IntPrice_s = 0$ and the scheduled power flow does not have to be maintained (typical implementation of current LFMs, e.g., PICLO platform), the DSO has no incentive to activate any upward flexibility. In that case, the rebalancing of the 4 MW is done with the flexibility from the transmission grid. The other extreme would be a Fragmented CS in which the expected power flow over S1 has to be preserved. In this scenario, the DSO has to rebalance the system using FSP 1 and 2, necessarily.

In between the unpriced Fragmented and the fixed interface power flow Fragmented CSs, different values for $IntPrice_s$ would lead to different costs for the system (total cost of flexibility procurement for both SOs) as well as different cost allocations. In fact, any interface price between 10 and 30 €/MWh would lead to the least cost of flexibility procurement in this simplified case study. It would incentivise the DSO to activate 2 MW downward from FSP 1 and leave the rest to be rebalanced by the TSO. The difference would be in the cost allocation between the TSO and DSO. Following Marques et al. (2023), it is possible to verify which would be the optimal interface price by checking the dual variable of the interface power flow constraint on the Common CS. In this case it is the equivalent of $\lambda^{T1}_{i,j,s,s'}$ in the (4.2b) of the Common CS, which is computed at 18.53 €/MWh. This value is not only a possible optimal solution in terms of total procurement cost but also leads to an optimal cost allocation, meaning the DSO pays to the TSO exactly the necessary for the rebalance to be completed. In other words, the cost for the TSO is the same as in the case of no congestions at the distribution network. Table 4.2 exemplifies this effect.

When running the bilevel model proposed in Subsection 4.2.2, the TSO strategically sets the interface price $intprice_s$ at 30 €/MWh. At this price, the DSO is indifferent at activating the FSP 2 or paying the TSO. Assuming that in this situation the DSO does pay to the TSO (e.g. lower transaction cost to pay the rebalance price than activating an FSP), the TSO would be extracting the highest profit possible. Figure 4.3 presents a sensitivity analysis on the interface price with respect to the costs for the different SOs (considering activation costs and transfers over interface imbalances), as well as the total cost for the system. The highlighted areas show the benefits and losses from cost allocation generated by a strategically set price of 30 €/MWh, in detriment to the optimal 18.53 €/MWh.

4.3.2 102-bus Case Study

This case study is composed of one 30-bus transmission network of 135 kV and four 18-bus DSOs of 12.5 kV. The transmission network is based of the IEEE-30 case study, also included in the MATPOWER package for MatLab as *case30* (Alsac and Stott, 1974; Ferrero et al., 1997; Zimmerman et al., 2011). The generators are the flexibility providers for the congestion management market. The four distribution networks are equal in terms of topology, electrical parameters and loads, and are based on the work of Grady et al. (1991) and Grady et al. (1992). These networks are also included in the MATPOWER package as *case18*. The original data, however, does not in-

		No DSO Congestion	With DSO Congestion		
	Interface Price	*NA*	*10*	*18.536*	*30*
	Activated Flexibility				
	Upward				
A	Energy (MWh)	211.59	209.79	210.69	210.69
B	Avg. Unit. Cost (€/MWh)	20.00	20.00	20.00	20.00
C	Total Cost Up. (AxB; €)	4,231.82	4,195.86	4,213.84	4,213.84
	Downward				
D	Energy (MWh)	211.59	213.79	212.69	212.69
E	Avg. Unit. Cost (€/MWh)	50.00	50.00	50.00	50.00
F	Total Cost Dw. (DxE; €)	10,579.55	10,689.66	10,634.61	10,634.61
	Interface Settlement				
G	Imbalanced Flexibility (A - D; MWh)	NA	-4.00	-2.00	-2.00
H	Interface Price (€/MWh)	NA	10.00	18.54	30.00
I	Imbalance Payment (+) or Revenue (-) (GxH; €)	NA	-40.00	-37.07	-60.00
J	TSO Cost (+) or Profit (-) (C+F+I; €)	14,811.37	14,845.53	14,811.38	14,788.45

Table 4.2: Costs for the TSO for the Stylised Case Study and different interface prices.

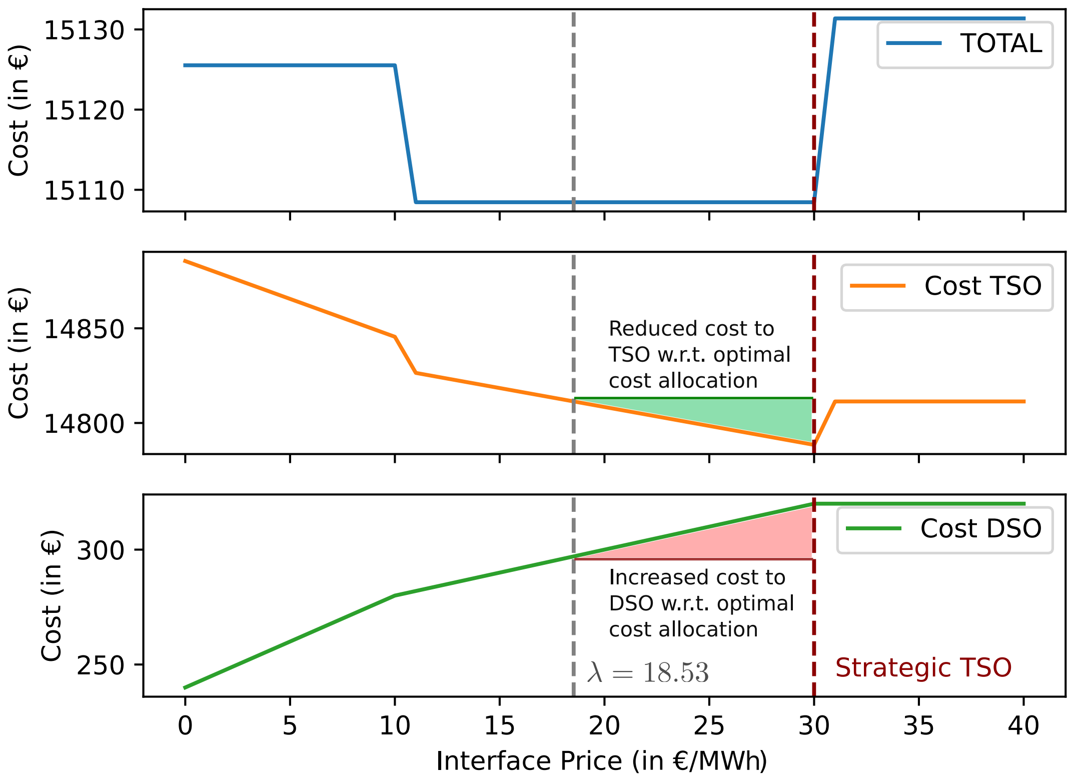

Figure 4.3: Results for the Stylised Case Study

clude line ratings, which are considered to be between 1.5 MVA and 6 MVA[3]. The placement of FSPs is randomised for downward providing units (rebalance capability). For upward flexibility, one unit is placed downstream of the distribution congested elements.

Figure 4.4 provides the network diagram for the 102-bus Case Study. The congestions occurring at both transmission and distribution networks are highlighted in red on Figure 4.4. At the distribution networks congestions on lines 1003-1004 and 3021-3023 are verified, while line 6-8 on the transmission grid is also overloaded. These congestions are created by lowering the line rating of these elements. In order to choose the overloaded elements, a power flow with the original data is computed, and the lines with closest power flow with respect to line ratings are chosen, therefore minimising the line rating modification. Detailed data for both case studies can be found in appendix D and Lind et al. (2024b).

The simulations conducted include not only the base case, but also a sensitivity analysis over two parameters: (i) the bid price from FSPs connected at the transmission level and (ii) the available flexibility from FSPs connected at the distribution network. The objective for these sensitivities is twofold. First, to explore scenarios in which the DSO does not have enough flexibility to rebalance their LFMs. Second, to evaluate how different flexibility prices for the TSO might impact the total cost and cost allocation, going from a flexibility that is always cheaper than the DSOs' to an always more expensive one. Therefore, in each run, the Base Case parameters $P^{-,+}_{k\in K^{DSO}}$ and $Bid^{up,dw}_{k\in K^{TSO}}$ are multiplied by the sensitivity factors S^1 and S^2, respectively. Ranges for S^1 and S^2 are presented in Table 4.3.

Parameter	Sensitivity range	Sensitivity purpose
$P^{+,-}_{k\in K^{DSO}}$	$S^1 = [\,0.15 \quad 0.20 \quad \ldots \quad 0.95 \quad 1.00\,]$	Study different levels of distributed flexibility provision available to the DSO.
$Bid^{up,dw}_{k\in K^{TSO}}$	$S^2 = [\,0.25 \quad 0.50 \quad \ldots \quad 3.75 \quad 4.00\,]$	Study the effects of transmission-connected flexibility on total cost and cost allocation.

Table 4.3: Sensitivity factors for the 102-bus Case Study.

Additionally, two scenarios are considered. First, no congestions at the transmission level occur. Only the congestions in DSOs D1 and D3 take place. Second, the congestion at the transmission level is included (line 6-8, as shown in Figure 4.4).

From the CS's perspective, several are simulated. First, the Common CS is simulated to provide the first-best solution in terms of flexibility procurement cost. Moreover, the Common CS is used to compute the optimal interface price. This price is used in a Fragmented CS with optimal

[3]The values are chosen so that the power flows from the original data sets are close to the line ratings. In this manner, congestions can be more easily observed or created. Nevertheless, the values are computed from examples of MV cables found in the industry. Line ratings of 1.5 to 6 MVA would correspond to continuous current ratings of 70 and 277 A, respectively, at 12.5 kV. These values are compatible with the ampacity of overhead three-core cables with copper conductor of cross-section ranging from approximately 16 to 95 mm^2, respectively (TFK, 2023).

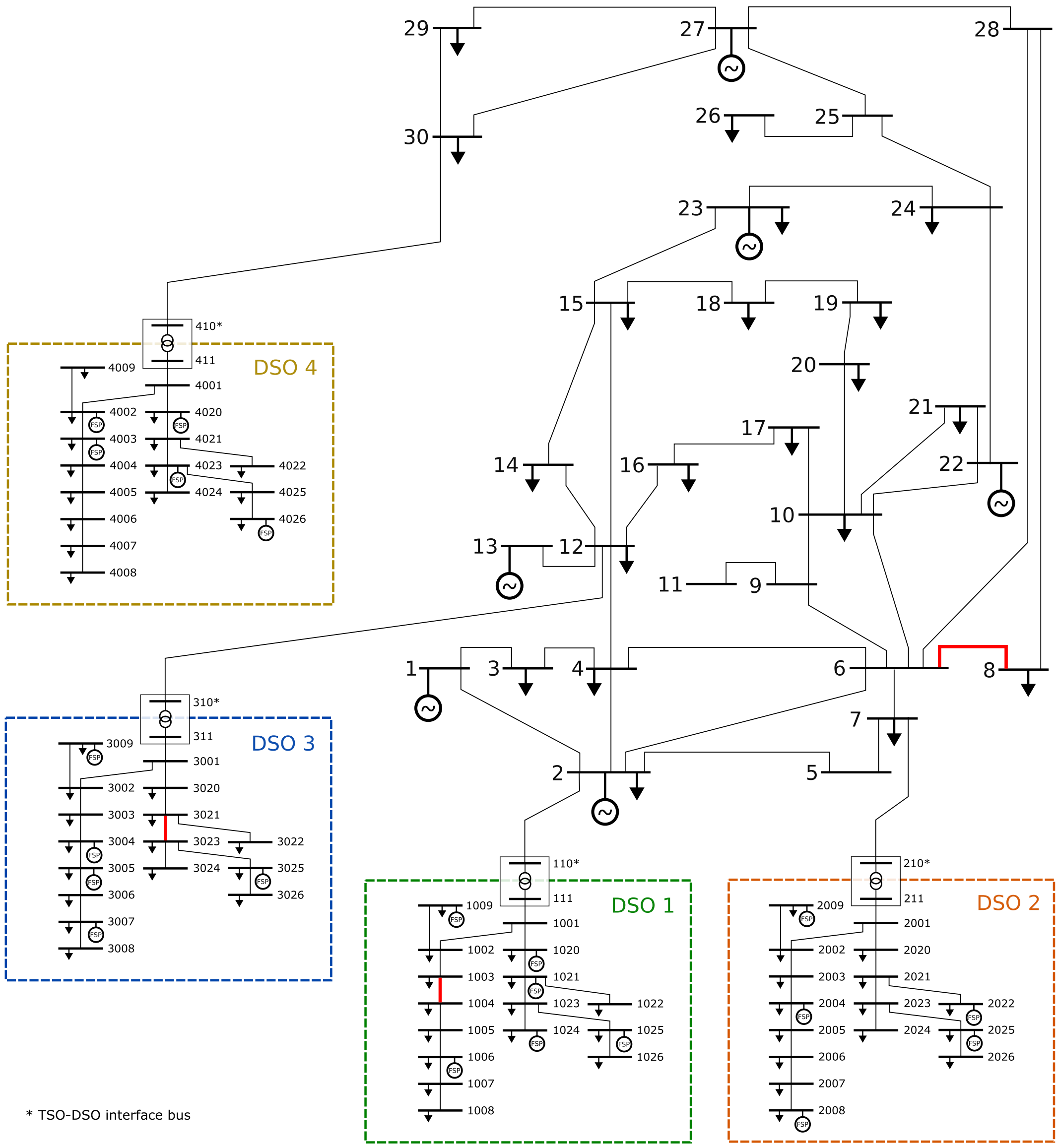

Figure 4.4: 102-bus Case Study network representation. Congested lines in red.

interface pricing run. In this CS, the interface price is fixed at the $\lambda^{T1,*}_{i,j,s,s'}$ from the Common CS. This Fragmented-Optimal has important properties for the analysis of the strategic cases: (i) it leads to the same total cost for the system as the Common CS, and (ii) allocates the rebalancing costs optimally among SOs, as argued in subsection 4.3.1. Finally, the Fragmented with Strategic TSO CS is computed. The latter is tested both in its standard case, as well as with additional regulatory mechanisms, as presented in the following subsections.

4.3.3 No congestion in the transmission network

The scenario in which no congestions occur at the transmission level has an important property for the evaluation of total cost and cost allocation: the cost for the TSO should be zero. From a cost allocation perspective, all flexibility costs should be borne by the DSOs, as no flexibility needs are generated at the transmission grid.

At the Base Case (no sensitivity factors applied), the total flexibility procurement cost is 416 € for both the Common and the Fragmented-Optimal CSs. The Fragmented-Optimal shows that both DSOs 1 and 3 activate upward flexibility downstream of their congestions and leave the downward rebalancing to the TSO, as the marginal unit at transmission bids 21 €/MWh, and so is the interface price for both DSOs (as network conditions do not affect these activations, in this case). In this case, the TSO receives the exact amount they need to activate the FSP $KT2$. When analysing the sensitivities results, however, it is possible to observe the case in which the FSPs at transmission are more expensive than the ones at distribution, and therefore, the DSOs are incentivised to activate their own downward flexibility. When the sensitivity factor over the available downward flexibility is also enforced, the DSOs 1 and 3 are not able to individually complete their rebalancing. In this case, the optimal interface pricing from the Fragmented-Optimal CS enables the TSO to receive the imbalance payments from DSOs 1 and 3 and pay this amount to DSO 2 so that the rebalancing is completed using the cheapest units in the system. In this case, the TSO's flexibility cost is still zero. They only act as a settlement party among the DSOs.

When the TSO is allowed to act freely in a strategic way, profits are generated in both the base case and under sensitivity factors. In the case of the latter, the TSO arbitrages the flexibility prices among the different DSOs. Table 4.4 provides an example of a settlement on the strategic case.

Figure 4.5 presents the results for the sensitivity analysis of the scenario with no congestion at transmission. The upper plot shows the absolute values paid by all four DSOs in net terms for the Fragmented-Optimal CS (which in this case is also the total cost for the system), while the lower plot shows the difference in p.u. between the Fragmented-Strategic and the Fragmented-Optimal. In the worst cases, the costs for the DSOs are almost three times higher than the optimal cost and on the best cases, 1.6 times higher.

4.3.4 Congestion at the transmission network

The case with congestion at transmission is used not only to compute the gap between the Fragmented-Strategic results to the optimal (Common; Fragmented-Optimal), but also to test additional regulatory proposals.

As mentioned in Section 4.1, modelling a purely strategic TSO is an academic exercise, as TSOs are regulated companies (Pérez-Arriaga, 2014). Therefore, considering a purely strategic TSO is

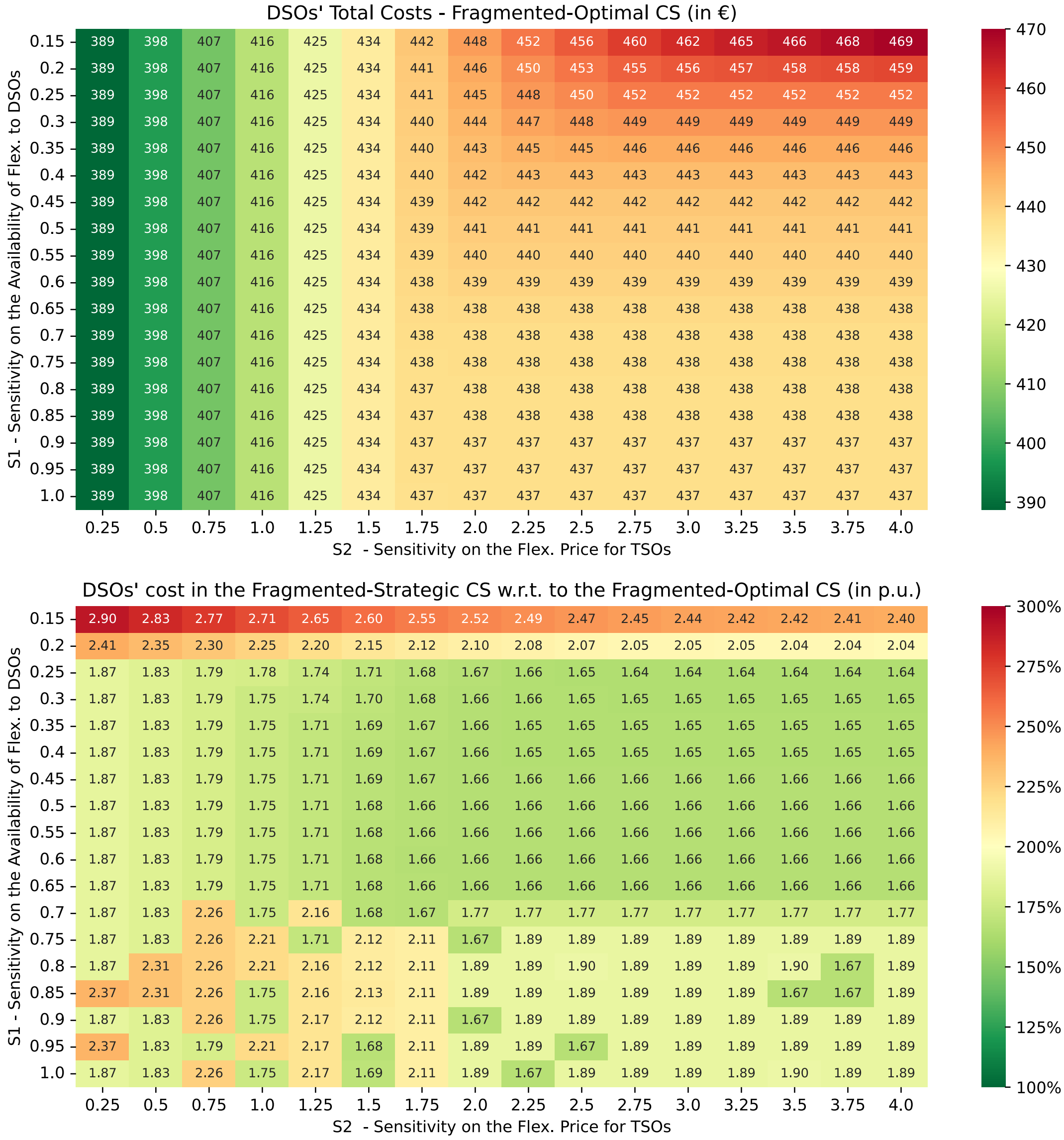

Figure 4.5: Results for scenario with no congestion at transmission.

		TSO	DSO 1	DSO 2	DSO 3	DSO 4
	Activated Flexibility					
	Upward					
A	Energy (MWh)	0.00	1.25	0.00	0.50	0.00
B	Avg. Unit. Cost (€/MWh)	0.00	128.00	0.00	439.00	0.00
C	Total Cost Up. (AxB; €)	0.00	160.00	0.00	219.50	0.00
	Downward					
D	Energy (MWh)	0.00	1.35	0.00	0.20	0.20
E	Avg. Unit. Cost (€/MWh)	0.00	36.00	0.00	38.00	29.00
F	Total Cost Dw. (DxE; €)	0.00	48.60	0.00	7.60	5.80
	Interface Settlement					
G	Imbalanced Flexibility (A - D; MWh)	-	-0.10	0.00	0.30	-0.20
H	Interface Price (€/MWh)	-	41.00	41.00	1,000.00	29.00
I	Imbalance Payment (+) or Revenue (-) (GxH*; €)	- 290.10	-4.10	0.00	300.00	-5.80
J	Total Cost (+) or Profit (-) (C+F+I; €)	- 290.10	204.50	0.00	527.10	0.00

* Except TSO. For TSO: $-\sum_{DSO}$ I

Table 4.4: Example of Settlement. CS: Fragmented-Strategic. Sensitivity factors: $S^1 = 0.45$, $S^2 = 3.5$.

not a realistic assumption but serves to understand potential incentives, identify eventual regulatory risks and allow for the proposal of regulatory mechanisms. In this context, four regulatory proposals are tested on the scenario with transmission and distribution congestions. First, the purely Fragmented-Strategic TSO, in which no policy is applied other than the cap on the interface price enforced by (4.3b). Second, the unpriced Fragmented CS, as this CS is the simplest implementation and is already being implemented in some countries or pilot projects, as discussed in Section 4.1. Third, the Fragmented with midpoint interface pricing is tested. The midpoint interface pricing was first proposed by Marques et al. (2023) and consists of pricing the interface flow between the most expensive downward flexibility bid and the least expensive upward flexibility bid of each DSO. This proposal is meant to offer a practical solution to interface pricing when optimal pricing is not implementable while retaining some of the benefits of interface pricing. Forth, a novel regulatory mechanism is proposed and tested, in which the interface price is limited by a cap and floor mechanism. The cap and floor are computed based on the weighted average of all downward bids in the system multiplied by cap and floor factors (4.6). The $LimitFactor^{floor}$ is set at 0.5 while $LimitFactor^{cap}$ is set at 1.5.

$$IntPrice_s^{+,-} = \left(\frac{\sum_k Bid_k^{dw} \cdot P_k^-}{\sum_k P_k^-} \right) \cdot LimitFactor^{cap,floor} \tag{4.6}$$

This would provide a band of possible interface prices according to the downward flexibility markets on the system. The TSO is assumed to be strategic within this band of possible values.

Under this proposal, first, the regulatory risk for strategic behaviour is minimised. Second, it considers downward bids from the whole system, allowing, to some extent, for cheap downward bids from one SO to be used by the other, as seen in the scenario with no congestions at transmission. Third, it mitigates a potential risk of midpoint proposal, namely manipulation of interface prices by FSPs. Under the midpoint pricing, the extremes of the merit order lists are used for each DSO. By knowing this, market participants, too, can act strategically (e.g. one unit artificially elevating the interface price by setting a high downward flexibility bid so another unit can be activated). The cap and floor proposal, however, comes at the expense of some information exchange of downward bids, although simplifications are possible (e.g. DSOs only send aggregated weighted average to the TSO or the party responsible for interface pricing calculation).

The Common and Fragmented-Optimal CSs are then used as a baseline for the performance of each of the four policy proposals. In that regard, this research confirms the findings in Marques et al. (2023). In all case studies, when the optimal price for the interface flow is used on a sequential Fragmented CS (models (4.1) and (4.2)), the total flexibility procurement cost is equal to the Common CS.

The network scenario with congestions at both transmission and distribution (as depicted in Figure 4.4) is simulated for all sensitivity factors proposed in Table 4.3. Results are presented in Figure 4.6. The heat maps illustrate the gap between the specific simulation and the optimal solution (i.e. Common; Fragmented-Optimal) in percentage, according to the colour scale for each case. Results are presented in three columns of plots. The first illustrates the gap between the total flexibility procurement cost of the specific policy proposal to the optimal (i.e. Common;Fragmente-Optimal). The second and third columns show the deviation in cost allocation for the TSO and DSOs, respectively. Numbers presented in the centre of each heat map represent the average of all 288 sensitivity runs on each heat map.

Results show that the purely strategic TSO distorts cost allocation greatly by reducing TSO's cost by 58.8% and increasing the cost to DSOs by 79.6% in relation to the Fragmented-Optimal CSs. However, the total cost in terms of procured flexibility is only increased by 0.44% in relation to the Common CS. Among all four policy proposals, this is the least distorted total cost, demonstrating that a purely strategic TSO has the incentive to price interfaces in a way that the most efficient flexibility units in the system are activated.

The "no interface price" policy, as expected, produces a cost allocation distortion in benefit of the DSOs, reducing their costs by 11%. The imbalance costs are passed on to the TSO, which sees an increase of 11%, while the total cost is increased in 2%. The increase in total and TSO costs is higher on cases in which the cost of transmission-connected flexibility is higher (right side of heat maps).

The Midpoint interface price produces an increase in total cost of 3% while maintaining the cost of the TSO nearly unchanged and increasing the cost for DSOs in 7.5%. The higher increases of cost (both for DSOs and total cost) happen on the region where transmission-connected flexibility is cheap. By setting the interface price only using each DSO's downward flexibility bids, distribution operators cannot benefit when downward flexibility bids at transmission are cheaper.

Finally, the cap and floor mechanism with strategic TSO produces a higher total cost of 0.9%, while cost distortions to TSO and DSO are -4% and +8%, respectively. This demonstrates that the TSO still exercises its strategical advantages reducing its cost and increasing the ones of DSOs, especially on the region where the flexibility available to DSOs is low (upper rows of heat maps).

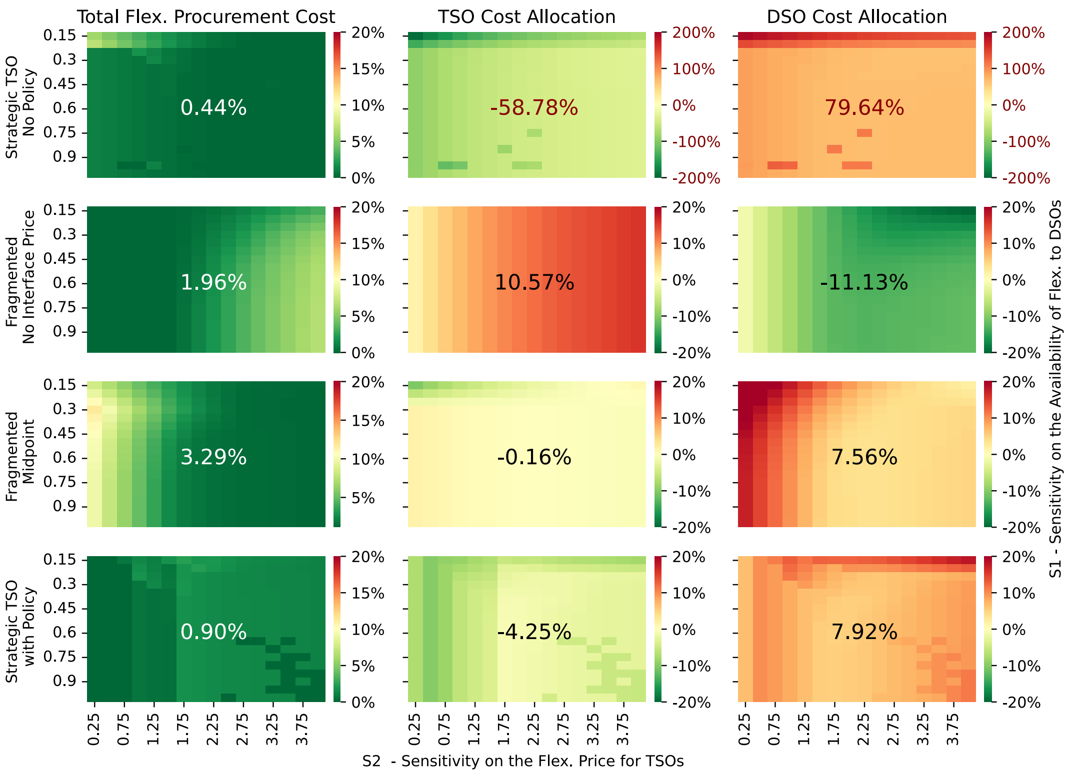

Figure 4.6: Results for the scenario with congested at both transmission and distribution and the four policy proposals. Average deviation with respect to the Common CS (for total flex. procurement) and Fragmented-Optimal (for cost allocation) per heat map on the centre.

However, the total cost is increased in 0.9%, second only to the purely strategic TSO, showing that the TSO still retains some incentive to price interfaces so it leads to efficient activations.

In order to further analyse the cap and floor mechanism, a sensitivity analysis is conducted on the parameters $LimitFactor^{cap}$ and $LimitFactor^{floor}$ and presented in Figure 4.7. Each box plot presents the statistics for the 288 sensitivities according to Table 4.3. The sensitivity analysis starts with a $LimitFactor^{cap,floor} = 1$, meaning that the TSO has no strategic capability and interface flow prices are set at the weighted average of all downward bids in the system. At each step, the $LimitFactor^{cap,floor}$ is widened in 0.1 up and down, given more flexibility to the TSO. Figure 4.7 shows sensitivities from $LimitFactor^{cap,floor} = 1$ to $LimitFactor^{cap,floor} = [2; 0]$.

This sensitivity analysis further corroborates the finding that the most strategic is the TSO, the lower is the total flexibility procurement cost and higher are the distortions in cost allocation. At the starting step ($LimitFactor^{cap,floor} = 1$), given the case characteristics, the highest procurement cost is observed together with a low cost allocation distortion. As the TSO is progressively allowed a wider band, total costs decrease and distortions get higher. A minimum in terms of average total cost seems to reached at $LimitFactor^{cap} = 1.8$ and $LimitFactor^{floor} = 0.2$. However, the wider the band, the wider get the distributions of cost allocation distortions, meaning the DSOs are more at risk of being in scenarios of high cost distortions in favour of the TSO.

An extended sensitivity range is also simulated and presented in Figure 4.8. In addition to the initial range from 1 to [2;0] shown in Figure 4.7, the range is extended up to $LimitFactor^{cap} = 8$, meaning that the $LimitFactor^{cap}$ can up to 8 times the value of the weighted average of all downward bids. This upper bound of 8 is selected as, for this case study, the highest value reached by the $IntPrice_s^+$ is 1,106 €/MWh, which is similar to the initial parameter consider for the fully strategic case presented in Figure 4.6[4].

The extended sensitivity analysis allows for the observation that the average total flexibility procurement cost reaches a minimum between $LimitFactor^{cap}$ = 1.8 to 2.0 (as also observed in Figure 4.7). Within this range, the median total cost is equal to the results from the Common or Fragmented-Optimal (optimally priced). However, after this point, it increases up to 0.4%, which is also observed for the Strategic TSO with no Policy in Figure 4.6. In terms of cost allocation distortion for the TSO and the DSO, the linearly decrease and increase, respectively.

4.4 Policy discussion

While modelling a purely strategic TSO is not a realistic assumption, it is worth identifying situations in which strategic behaviours might arise. Even if regulation mandates TSOs to efficiently compute interface prices (efficiency would vary according to the level of information available), a significant asymmetry of information would exist between the TSO and the regulatory authority. Assuming that interface prices could be computed for high time and network granularity (e.g. every hour for tens or hundreds of interfacing substations) and the complexity of calculations,

[4]Results, however are not equal. The value of 1,106 €/MWh is only reached when S^2 = 4, as $LimitFactor^{cap,floor}$ is directly impacted by S^2, while in the strategic case, $IntPrice^+ = 1,000$ is applied to all sensitivity runs. For this reason, in the strategic case of Figure 4.6, the worst case scenarios for the DSO, for instance, reach almost 200%, while in the extended sensitivities plot of Figure 4.8 they go up to 160%

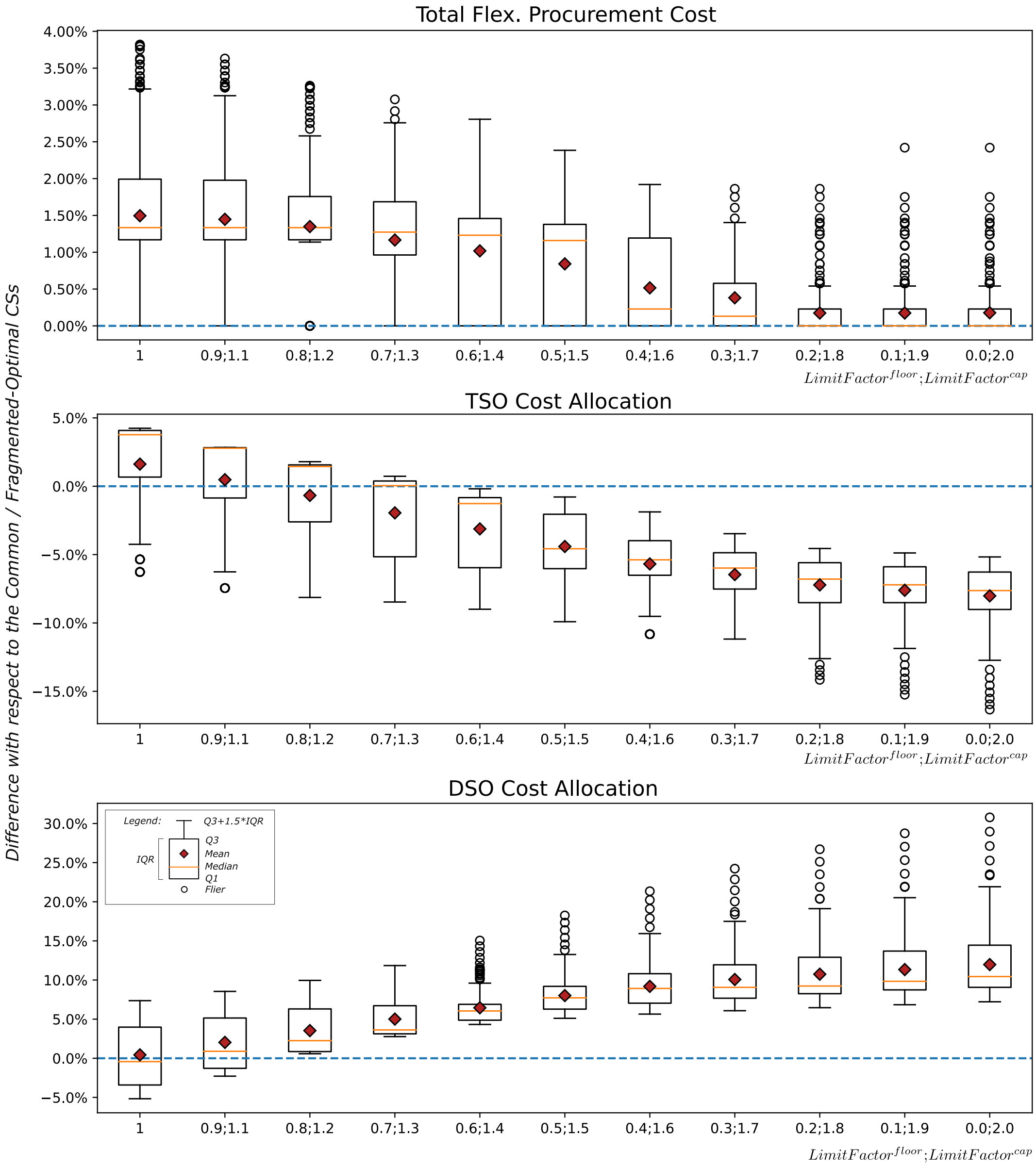

Figure 4.7: Sensitivity analysis over the cap and floor parameters.

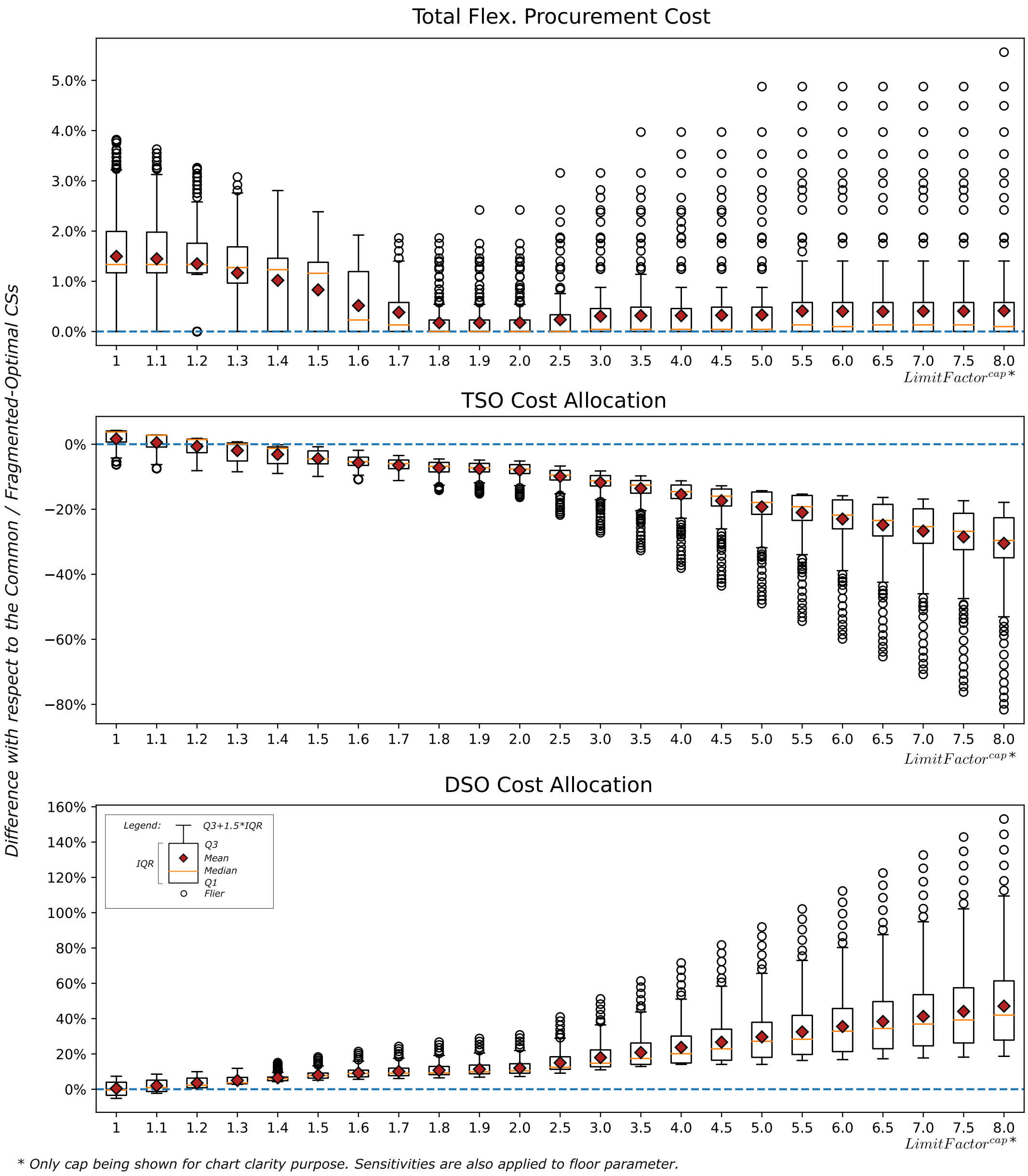

Figure 4.8: Extended sensitivity analysis over the cap and floor parameters.

regulators would have a low capability for verification. In this context, we show that distortions are higher in situations where DSOs have a low liquidity in their flexibility markets. This happens both in a purely strategic TSO and when a cap and a floor to the interface prices is applied, as the TSO exploit their strategic position to a greater extent, leading to higher cost allocation distortions, as shown in Figure 4.6.

Results also show that the current implementation of LFMs in which the DSO does not have any incentive to rebalance their flexibility activations may lead to poor results in terms of total cost as well as cost allocation. However, the results shown are case-dependent, and a trade-off exists between having some cost distortions and introducing a more complex and costly mechanism to solve them. It is possible that at early stages of distributed flexibility usage, when distortions caused by LFMs are not so representative at a system level, introducing complex interface pricing mechanisms could jeopardise the development of these LFMs.

The Midpoint interface pricing is a simple method of easy implementation that has the advantage of not requiring information exchange. However, it also creates cost distortions as shown in the 102-case study results, and therefore, a cost-benefit analysis on its implementation should be conducted on a case-by-case basis.

The cap and floor proposal led to favourable results in the cases analysed. However, results are also case-dependent. Moreover, it assumes a strategic TSO, although strategic behaviour is bounded. This means that, intrinsically, a cost allocation distortion in favour of the TSOs is to be expected. On the other hand, it illustrates that a TSO that has incentives to efficiently price substations could lead to lower total costs in terms of flexibility activation. It is important to notice that the actual cost to the system is the activated flexibility (e.g. the sum of C and F on Table 4.4). The settlement for interface pricing (e.g. I on Table 4.4) is a financial transfer from one SO to the other.

Although the TSO benefits by exploring potential gains on interface pricing, the TSO is also the one enabling the coordination of efficient flexibility procurement among all SOs in a given control zone. A case could be made that this coordination is a service to the system and that this could be remunerated in some form. The cap and floor mechanism proposed in this research is primarily a proof of concept that illustrates a form of dedicated incentive for TSO-DSO coordination. Dedicated incentives are a known and widely used regulatory mechanism used for specific purposes, on top of general incentive regulation schemes (e.g. RPI-X). An example is the use of dedicated incentives for the development of offshore grids, a riskier and newer type of investments to be done by TSOs (Lind, 2017).

From the DSO's perspective, actions could be taken in order to minimise cost allocation distortions. Considering that the regulatory mechanism proposed does not require intensive supervision, regulatory authorities could focus eventual supervision efforts on situations in which distortions are potentially higher, i.e., when liquidity in the DSO's LFM is low, as shown in Figure 4.6. Moreover, expected distortions could be offset by including them in the set of incentives DSOs are expected to have in order to procure flexibility, as mandated by European regulation (European Commission, 2019a).

Actual implementation of the mechanism, besides benefiting from further studies, would also depend on regulatory choices, which would often lead to a trade off between efficiency and practicality. For instance, the case studies considered in the chapter are for a single hour. Therefore, the DSO's and TSO's markets are cleared simultaneously. However, it could be possible to have asynchronous markets and interface flow prices, although these dynamics should also be investigated. Alternatively, if interface flow are somewhat stable, interface flow prices could be set for blocks of hours or on even less granular intervals. These would impact economic efficiency, but would also make the mechanism simpler.

Alternatively, other options using the interface flow pricing mechanism could be investigated other than considering or allowing the TSO to be incentive-driven. It is assumed by the Stackelberg game that the TSO has perfect information over the DSOs' markets, as discussed previously. This could also mean that, upon a regulatory mandate, the TSO is required to compute the optimal interface price without having the incentive to deviate from this optimal. However, such assumption creates other problems such as the need for tighter regulatory supervision, for instance. Nevertheless, these alternatives should be studies and discussed in future studies.

4.5 Conclusions

In this chapter, a bilevel model is proposed to evaluate how a strategic TSO would act in a Stackelberg game environment in which the interface flow price is set first and freely by the transmission operator. Although assuming a purely strategic TSO is not a realistic assumption, it provides important benefits to the investigation of possible regulatory implementations.

First, it identifies the situations in which potential distortions would be greater, namely in situations with low liquidity at the LFMs of the DSOs. This can be used by regulatory authorities to direct eventual verification in a context of high asymmetry of information and limited regulatory resources.

Second, it provides a research environment for the testing of different policy alternatives. While the purely strategic TSO is an unrealistic extreme, different regulatory mechanisms can be tested and compared. The results obtained demonstrated that a strategic TSO has the incentive to activate or price interfaces so that the most efficient flexibility providers are activated. Leveraging on these results, a cap and floor regulatory mechanism is proposed. This mechanism poses bounds to strategic behaviours by the interface price setter, but still gives an incentive for the activation of economical FSPs. This mechanism compared favourably against other options. It was the realistic mechanism that led to the least distortion of total cost. On a sensitivity analysis of 288 simulations on a 102-bus cases study, the cap and floor mechanism led to an average increase by 0.90% in total cost with respect to the first-best reference (i.e. a Common CS), against 1.96% and 3.29% for the vanilla-Fragmented and the Midpoint options, respectively.

While providing a modelling sandbox for regulatory mechanisms, this chapter also indicates that indirect sharing of resources through interface pricing is an efficient and implementable way of achieving TSO-DSO coordination for distributed flexibility procurement. Moreover, it indicates that mechanisms that are low in regulatory supervision can lead to efficient second-best options in terms of total cost and cost allocation, when compared to the first-best but technically complex Common CS.

The proposed cap and floor on interface prices is an example that requires future research. More elaborate mechanisms could be proposed, such as a bonus-malus, which is already a typical type of dedicated incentive for TSOs and DSOs. Moreover, meshed-to-meshed topologies should be considered, representing the typical typologies adjacent to TSO-DSO interfaces in Europe. This study could also be expanded to include voltage violations in addition to overloads. Considering that voltage violations are a typical congestion type for DSOs, the model could readily be used in case studies in which voltage problems are solved only using active power (e.g. exploiting the monotonic decreasing of voltage magnitude along feeders), or expanded to include reactive power trading and activation.

Different conditions in the downward markets should also be explored, to understand potential differences when there is a large difference between FSPs connected to the transmission grid (i.e., which are also wholesale market participants) and DERs. The former could have the incentive to pay the SO a value slightly below the value in which the energy was sold in the wholesale energy market, while the latter could have a weaker incentive to do so, and would demand a payment for downward regulation as it could potentially represent a decrease in comfort or burden to provide the service.

Finally, this study should be extended to account for the possible effects of FSP strategic behavior. These behaviours are also being explored in the literature, such as the "inc-dec" (an acronym for "increase-decrease") behaviour, which FSPs could use to game flexibility markets.

5 Regulatory Aspects for TSO-DSO Coordination[1]

In this chapter, regulatory conditions for TSOs-DSO coordination are examined. This chapter is divided into two parts. First, different flexibility-related Business Models (BMs) are identified and a comprehensive stakeholder consultation is conducted, which allowed for a myriad of concerns to be identified on different flexibility-related Business Models (BMs). Second, a regulatory country assessment is presented for eight European countries, exploring barriers previously identified. A regulatory assessment is proposed and map of regulatory compatibility produced, showing that TSO-DSO coordination under several Coordination Schemes (CSs) still face important regulatory barriers.

[1]This chapter is based on the following journal papers, conference papers and reports:
Journal papers:

- L. Lind, J. P. Chaves-Ávila, O. Valarezo, A. Sanjab, and L. Olmos (2024a). "Baseline Methods for Distributed Flexibility in Power Systems Considering Resource, Market, and Product Characteristics". *Utilities Policy* 86, p. 101688. ISSN: 0957-1787. DOI: 10.1016/j.jup.2023.101688
- C. Valor, L. Lind, R. Cossent, and C. Escudero (2021). "Understanding the Limits to Forming Policy-Driven Markets in the Electricity Sector". *Environmental Innovation and Societal Transitions* 40, pp. 645–662. ISSN: 2210-4224. DOI: 10.1016/j.eist.2021.10.022
- O. Valarezo, T. Gómez, J. P. Chaves-Avila, L. Lind, M. Correa, D. U. Ulrich Ziegler, and R. Escobar (2021). "Analysis of New Flexibility Market Models in Europe". *Energies* 14:12, p. 3521. DOI: 10.3390/en14123521

Conference papers:

- L. Lind, R. Cossent, and P. Frías (2019b). "New Business Models Enabled by Smart Grid Technology and Their Implications for DSOs". In: *Proc. of the 25th International Conference on Electricity Distribution (CIRED 2019)*. DOI: http://dx.doi.org/10.34890/564
- L. Lind, C. Valor, R. Cossent, V. Labajo, and C. Escudero (2021a). "New Business Models at Distribution Grids: A Stakeholder Consultation". In: *CIRED 2021 - The 26th International Conference and Exhibition on Electricity Distribution*. Vol. 2021, pp. 3140–3144. DOI: 10.1049/icp.2021.1496

Technical reports:

- L. Lind and J. P. Chaves Ávila (2019). *CoordiNet D1.1 - Market and Regulatory Analysis: Analysis of Current Market and Regulatory Framework in the Involved Areas*. Technical report
- R. Cossent, L. Lind, O. Valarezo, M. Troncia, and J. P. Chaves (2022). *CoordiNet D6.4 - Scalability and Replicability Analysis of the Market Platform and Standardized Products*. Technical report

5.1 Introduction

As shown in Chapter 2, the need for enhanced coordination between TSOs and DSOs is originated in several changes currently being observed in power systems. Among those, the use of distributed flexibility by TSOs and DSOs is a key reason. While Chapters 3 and 4 have explored possible ways to coordinate the procurement and activation of distributed flexibility from a techno-economic perspective, other barriers of different nature might still exist for the effective implementation of the flexibility usage. First, TSOs and DSOs will not only need to enhance coordination between themselves, but also with several different actors implementing several different business models. Several of these actors and business models are new, too. In addition, a regulatory layer falls onto actors, organising, bounding and indicating future developments for these new actors, markets, and business models. This regulatory layer, too, is developed and deployed according to its own dynamics, which might also pose challenges to efficient TSO-DSO coordination. In this Chapter 5, an analysis of aspects other than the techno-economic from previous Chapters is presented. Namely, the development of new business models and the regulatory barriers for TSO-DSO coordination.

In order to evaluate potential regulatory and business model barriers for flexibility services and TSO-DSO coordination, a two-fold methodology is used. First, the definitions of the associated BMs to distributed flexibility and TSO-DSO coordination is made and a stakeholder consultation is carried out with relevant actors. They are TSOs, DSOs, Regulators, Policy-makers, consumers and aggregators in four EU Member States. Second, a regulatory assessment on the conditions for TSO-DSO coordination in seven EU Member States is presented.

5.2 Use of Distributed Flexibility - A Stakeholder consultation

Business models can generally be understood as a way in which agents generate, perceive and capture value from a product or service. In fact, the literature on business models, although vast, is not precise in defining the concept. Zott et al. (2011) reviewed 103 business models publications and showed that more than one-third do not define the concept of business model, "taking its meaning more or less for granted", around half of them define it or cite the main components, and only 19% refers to the definition of other authors.

In Lind et al. (2019b), a business model for the purpose of distributed flexibility (from both the buyer and seller sides) is finally defined as a set of strategies chosen by a certain agent in order to generate economic benefit. These strategies can combine multiple business plans, and the economic benefits can be generated by different sources of revenue streams and/or cost reductions.

The existence of appropriate conditions for the development of new business models with regards to distributed resources is a necessary element so that TSOs and DSOs can access their explicit flexibility. Stakeholders (e.g. consumers, aggregators, TSOs, DSOs) should be able to perceive a benefit in the exploitation of distributed flexibility so that SOs can procure it in organized markets and/or bilateral agreements.

Behavioral and environmental motivations may play a role in the consumer's decision of providing flexibility. In the EU Horizon 2020 project InteGrid, behavioral demand response was generated by informing consumers on the environmental benefits generated by their flexibility provision and comparison of consumption with other participating customers (Mäkivierikko et al., 2023). Another example is the American company Opower. The company started by sending "reports and alerts, via mail and email, that compare consumers' energy use to their neighbors' and provide targeted energy saving recommendations" (United States Securities and Exchange Commission, 2014). Opower's revenues are generated by selling subscriptions of the software to utilities. These are examples in which a new business model is generated by companies exploiting behavioral demand response. However, it is typically assumed that the consumers too should receive a remuneration for their flexibility. In this setting, the consumer can sell their flexibility directly to the SOs or to an intermediary, such as an aggregator, that would finally sell the aggregated flexibility to TSOs and DSOs. Therefore, two business cases would exist, one for the consumer and aonther for the aggregator.

In Chapter 2 it is argued that the activities of DSOs will change. Among the most important changes for the DSO, is the procurement of flexibility from local resources for a more active management of the grid. In some sense, DSOs will get closer to the way TSOs manage their grids. DSOs may no longer resort to grid investments exclusively in order to solve potential operation constraints, also known as the "fit-and-forget" approach in distribution networks (equivalent to the "copperplate" approach in transmission networks). Instead, DSOs will balance network investments with local service acquisition in order to reach a lower network cost (Lind et al., 2019b). This evolution of the DSO understanding is illustrated in Figure 5.1. The reduction of CAPEX (e.g. by deferment of investments) minus the flexibility procurement OPEX can be also seen as a new business model, this time for the DSO, enabled by local flexibility, if incentivised by the DSO's remuneration scheme.

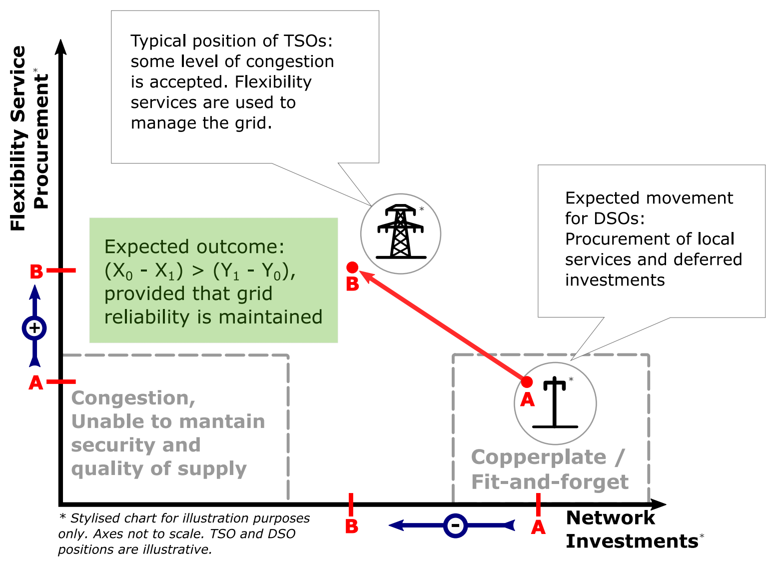

Figure 5.1: Expected change of operations' paradigm for DSOs.

Therefore, this section discusses the results of a research on new business models definition, a stakeholder consultation and an analysis on flexibility market formation. The analysis of business models, also from the optic of impacted stakeholders, can provide important insights on the barriers that TSOs and DSOs may face when trying to procure local flexibility.

5.2.1 Methodology

In Lind et al. (2019b), new BMs are identified for four main actors, namely the (i) DSO, (ii) data service providers, (iii) aggregators, and (iv) consumers. Each main actor promotes actions to achieve their objectives, that could be a reduction in cost (e.g. the DSO procuring flexibility) or generate profits (e.g. the independent aggregator). Table 5.1 summarises the four BMs considered in this chapter.

Main Actor	*Benefit*	*BM summary*
DSO	Investment deferral, RES curtailment cost reduction	The DSO uses flexibility from DER to manage the grid. As a result, investments may be deferred or RES curtailment costs reduced, reducing overall grid costs.
Data Service Provider	Revenue from data service provision	The new agent "data service provider" can act as an interface for customers and third parties to trade data and flexibility services.
Independent Aggregator	Revenue from aggregating flexibility and providing services to the TSO and/or DSO	The aggregator provides services to grid operators while using flexibility from DER. The flexibility from DERs is paid by the aggregator while TSO and/or DSO pays the independent aggregator.
Consumer	Reduced net electricity cost	By improving electricity management, installing DG and possibly providing grid services, consumers can reduce their overall electricity cost.

Table 5.1: Summary of Business Models considered. Adapted from Cossent et al. (2020b).

The most innovative BM for the DSO is the procurement of flexibility as mentioned above, as a way to promote savings in CAPEX. The exploitation of new business models for data service providers means that new data companies may be able to provide data services to end consumers (e.g. energy management systems that facilitate the flexibility provision), to aggregators (e.g. forecast provision, portfolio management) or to SOs (e.g. Opower platform). Business models for aggregators and consumers are those exemplified above: the selling of flexibility in SO's markets.

Beyond the definitions of these BMs (provided in details in Cossent et al. (2020b) and Lind et al. (2019b)), a stakeholder consultation was conducted in order to investigate the perceived drivers and barriers for their full exploitation. For this consultation, relevant stakeholder for each BM were identified. For that purpose, a power/attention matrix is used, based on the methodology proposed in Newcombe (2003). Therefore, the relevant stakeholders consulted go beyond the main actors listed above, including also regulators, policy-makers, industrial associations, retailers, current Energy Service Companies (ESCOs) and TSOs.

Interviews with representatives from the key actors in four different countries where conducted, following an in-depth personal interviewing methodology. The countries selected were Portugal, Slovenia, Spain and Sweden. Respondents were asked to discuss the perceived drivers and barriers, as well as other financial, regulatory or social feasibility issues related to these new business models.

In total, 31 personal interviews took place. To preserve anonymity, the role of the actor is reported, rather than personal details that could make the informant identifiable (Table 5.2). In addition, citation attribution is not made per nationality if this might make the informant identifiable.

Interviews followed a semi-structured approach. The analysis of the interviews led to the identification of drivers and barriers for each BM. Barriers were classified into regulatory, technological and organisational/behavioural. Additionally, the "level of agreement" was also observed. A high level of agreement means that most or all participants agree with the driver/barrier, while a medium level of agreement means that two or more participants mentioned/agreed on the same barrier. If drivers/barriers were mentioned by only one respondent, no level of agreement is reported.

Stakeholder	Portugal	Slovenia	Spain	Sweden	Total
End users (industrial association, prosumers representatives, DER owner)	2	5	1	1	9
System operators (DSO/TSO)	1/1	1/1	2/1	2/1	10
Retailer and energy service providers (ESCOs, Aggregator, Retailers)	1	2	2	1	6
Regulators/policy-makers	1	1	2	2	6
Total country	6	10	8	7	31

Table 5.2: Description of stakeholders interviewed by country and type.

5.2.2 Results from Stakelhoder Consulation

DSO procuring local flexibility for grid management

This BM is defined as the procurement of local flexibility from DER by the DSO (main actor) as a means to help manage the grid (e.g. solving local congestions or voltage problems). By doing so, the DSO could potentially benefit from reinforcement deferral or even avoidance.

The DSOs agree that procuring flexibility services will be part of their future, as a means to defer or avoid network reinforcements. However, they believe that regulation does not provide the certainty or incentives DSOs need to change the way they operate their networks. Firstly, the necessary economic incentives to promote the use of flexibility are missing. Secondly, they currently bear the full risk in case flexibility providers fail to provide the service, leading to grid problems and/or interruptions. Lastly, on the institutional realm, DSOs mentioned that they may face some internal resistance to adopt this BM.

Regulators generally agree that promoting the use of flexibility by DSOs is necessary if DERs keep increasing as expected. They mentioned that the current CAPEX-oriented regulation is an important barrier for DSOs, but did not have a clear view of where future regulation should go. Interviewees also mentioned the lack of local flexibility mechanisms as an important barrier. Some participants mentioned public consultations and pilots as a way to overcome this, while one interviewee remarked the importance to coordinate local flexibility procurement with tariff schemes.

TSOs expressed their concerns about the inefficiencies of local mechanisms, especially market-based ones, due to their lack of liquidity. From the grid operation standpoint, TSOs mentioned that congestions in the grid should be the exception, and not the norm. Additionally, they mentioned that forecasting will become more difficult for the TSO, and that TSOs and DSOs will have to share the responsibility of the security of supply.

Other stakeholders also commented on this BM. For instance, one DER owner deemed it difficult to provide the service to the DSO as they have no visibility over where and when flexibility will be needed, and the absence of clear pricing schemes. One policy maker mentioned that incentives are missing for both the DSO and the consumers. Retailers and ESCOs stated that additional hardware and communication would be necessary from their side. Likewise, aggregators were concerned about the lack of harmonisation of local flexibility products and procedures across Europe, jeopardizing the scalability potential of aggregation tools and operations.

Table 5.3 provides the final list of barriers and drivers identified in the interviews. Drivers and barriers are divided by stekeholder and type (e.g. driver, regulatory barriers, technological barrier, and organisational/behavioral barrier).

Stakeholders	Driver or Barrier
DSOs	(D) This BM is considered relevant and DSOs are already considering it internally (***) (B-R) Lack of economic incentives and financial compensation for flexibility procurement (***) (B-R) DSOs' role in demand flexibility buying is not enabled by current regulation (***) (B-T) Missing communication and interoperability mechanisms facilitating flexibility (B-I/B) Corporate inertia
TSOs	(B-R) Efficiency of local markets for congestion management (***) (B-R) Split of liquidity between TSO and DSO markets (**) (B-R) Forecasting becomes more difficult for the TSO (***) (B-R) Sharing security of supply responsibility between TSO and DSO (**)
Regulators	(D) Local flexibility procurement will be necessary in a scenario with DER penetration (***) (B-R) CAPEX bias in DSO revenue regulation (***) (B-R) Lack of local flexibility mechanisms (coordinated with grid tariffs)
DER Owners	(B-R) Lack of appropriate information regarding grid constraints (B-R) Lack of proper local flexibility pricing

continued . . .

Stakeholders	Driver or Barrier
Policy Makers	(D) In some countries, certain existing regulatory mechanisms can create opportunities for the DSOs to use local flexibility (e.g. subscription penalties in Sweden) (B-R) Lack of proper local flexibility pricing (B-I/B) Little economic incentives for consumers to provide flexibility
Retailers / Aggregators	(B-T) Additional infrastructure is required to provide local flexibility to DSOs (B-R) Different solutions across Europe may limit the replicability of solutions developed by aggregators
Legend: (D) Driver; (B-R) Barrier, Regulatory; (B-T) Barrier, Technological; (B-I/B) Barrier, Organizational/Behavioural; Level of agreement: (***) high, (**) medium	

Table 5.3: List of drivers and barriers for the local flexibility procurement by DSOs. Source: Lind et al. (2021a).

Data services and platforms

In this BM, a new (or incumbent) agent, here referred as a Data Service Provider (DSP) (main actor), uses metering data stored in central data hubs, if authorized to do so, to provide data services (e.g. forecasting, energy management, portfolio optimisation for aggregators), either in Business-to-Business (B2B) or Business-to-Client (B2C) modalities.

During the consultation, this BM captured different stakeholders' attention, including DSOs, industrial consumers, policy makers, retailers/ESCOs, aggregators, regulators, and a possible DSP. They emphasized the innovative approach that this BM implies.

Whilst they all agree that data platforms will necessarily develop and some stakeholders believe this will be useful, some stakeholders are sceptical of the value data platforms will create. The most relevant barrier, on which there is a general consensus, is the difficulties in accessing the data as required to provide data-driven energy services. The first reason may be the refusal or lack of interest of many end consumers to share their data. This can lead to a vicious circle in which consumers are not offered value due to the limited access to data, and consumers not accepting to sharing the data due to the low perceived value. As a possible solution, one DSP believed that some early consumers, who allow for using their data, could be offered cheaper retail deals in exchange, progressively leading to a change in behaviour. Nevertheless, another reason, which draws a very high level of agreement across stakeholders, is that data protection regulation limits innovative data service opportunities.

Besides the data access problem, interviewees identified two other important barriers. Firstly, a potential DSP mentioned that the EU is unlikely to harmonize the data access and procedures. That means that the DSP will have to create different solutions in different countries, which constitutes a major barrier, considering that data service provision will be a low-margin business and needs to be scalable to be profitable.

Another risk for this BM identified by one stakeholder is that technology companies are already gathering electricity-related data (or inferring this data) outside the metering infrastructure (e.g. Google, Amazon, through their "smart home" devices). That means that these companies could soon be able to offer very similar services in a much more dynamic business model, as they are less bounded by energy regulations.

Table 5.4 provides the final list of barriers and drivers identified in the interviews for this BM.

Stakeholders	Driver or Barrier
DSOs	(B-R) Prohibition of data use and data sharing (***) (B-I/B) Limited value of data services for DSOs
Regulators	(B-R) Strict data protection regulation hampers data access (B-T) Metering data is insufficient for some data services (need to include tariff or network information) (B-I/B) Lack of interest from incumbents and immature market for data
DER Owners	(B-R) The "data hub" should not be a single platform, but rather an environment of multiple interoperable platforms (B-T) Missing interoperable protocols that can link different platforms Communication and settlements (P2P) (B-I/B) Other players (e.g. technology companies) may take this market over with faster and more dynamic BMs
Policy Makers	(B-R) Prohibition and security reasons block data use and data sharing, even at a non-individual level (B-I/B) Consumers are the only data owners, limiting data access for research, even if not at individual level
Retailers / ESCOs	(D) Attractiveness of better offers for customers thanks to more information and competition (B-R) Data protection policy (B-T) Communication infrastructure
Legend: (D) Driver; (B-R) Barrier, Regulatory; (B-T) Barrier, Technological; (B-I/B) Barrier, Organizational/Behavioural; Level of agreement: (***) high, (**) medium	

Table 5.4: List of drivers and barriers for data services and platforms. Source: Lind et al. (2021a).

Customers providing flexibility

This BM is defined as the consumers (main actor), both residential and industrial, engaging in enhanced electricity management, adoption of DG and possibly the provision of grid services, aiming at reducing the overall electricity cost.

Several industrial consumers and one residential consumers' association participated in a discussion regarding this BM, as they are the main actors. Nevertheless, DER owners, policy makers, retailers and ESCOs, aggregators, regulators and TSOs, also provided their viewpoints.

From the industrial consumer's standpoint, the interviews showed mixed opinions regarding the interest and possibilities for this BM. Some industries, usually the large and energy-intensive ones, are already very advanced in terms of internal energy management, whereas smaller and less energy-intensive industries are less concerned about optimising energy usage (low benefits, or lack of resources to do so). These stakeholders mentioned high fixed regulated costs as a reason for the lack of interest in this BM.

On the provision of flexibility to grid operators, the industrial consumers also see different barriers. Some interviewees said they would participate in service markets, and some already do it (e.g. in tertiary reserve). However, others mentioned that they would not participate, as this would imply them changing their production schedules for a small benefit. Additionally, some industrials mentioned that they could not change their consumption to comply with balancing products requirements (traditionally tailored to centralized generators).

One residential consumer's association mentioned three main barriers, especially about flexibility provision: i) low price elasticity of consumers, ii) difficulty in understanding electricity markets, and iii) general mistrust in electricity companies. Therefore, consumers would be less willing to give away the control of their consumption for what they anticipate is a reduced economic benefit. Other stakeholders also expressed their opinions and concerns. The DG owners, for instance, highlighted that energy and service markets (e.g. balancing) are not completely open yet for DER participation. It was also mentioned the need for enhanced infrastructure (communication) for these services to be provided. Aggregators mentioned that individual consumers are less aware or motivated regarding new possibilities, but that it could be more attractive for community users. However, one aggregator sees regulatory uncertainty over energy communities as a barrier.

Regulators also commented extensively on this BM, particularly on the need to re-design electricity tariffs to promote an efficient behaviour from end-users. Interviewees recognized that current tariff structures do not promote flexibility, but several mentioned different barriers, such as the lack of sufficient historical metering data to support tariff design changes due to the recent smart metering deployment, fear of causing unintended consequences or complaints from end-users, or even the reluctance from some incumbents or policy-makers to these changes. Additionally, regulators identified aspects already mentioned before, such as the low interest from the consumer's side to adopt advanced tariff schemes due to the small benefit perceived.

Finally, TSOs also expressed their expectations and concerns. They recognize that DR participation will be very beneficial to overall efficiency of balancing markets. However, they expressed the possible internal resistance in TSOs due to doubts about the ability of DR to participate in complex and sensitive services for the system, such as fast frequency control (e.g. automatic Frequency Restoration Reserve (aFRR), FCR products). Interviewees identified technical requirements about observability, prequalification and product definition as barriers too.

Table 5.5 provides the final list of barriers and drivers identified in the interviews for this BM.

Stakeholders	Driver or Barrier
Industrial consumer	(D) Important business model for large and energy-intensive industry (B-R) Tariffs contain high regulated costs, diluting potential gains from flexibility provision (***) (B-R) Limited incentives and market development for procuring flexibility (B-T) Missing communication and interoperability mechanisms facilitating flexibility (B-I/B) Limited impact of energy costs on total costs (B-I/B) Lack of built-in capacity (e.g. personal) (B-I/B) Distrust of energy operators (including aggregators and ESCO) (B-I/B) Reluctance to adapt operations to system needs (B-I/B) Impossibility of operational adaption in certain industries (flexibility activated on a short notice)
Residential consumer	(B-I/B) Consumers are not very price sensitive (B-I/B) Difficulty in understanding electricity markets (B-I/B) Mistrust in electricity companies
Regulators	(B-R) Tariff structure that does not promote flexibility (B-R) Limited potential for self-generation (B-T) Lack of historical metering data to support tariff design changes (B-I/B) Consumers not interested in changing their behaviour: lack of information, small benefit perceived (**) (B-I/B) Static/conservative retail market and reluctance of incumbents to change (B-I/B) Limitations to test and implement innovative tariff designs
DER Owners	(B-R) For balancing participation, markets are not completely open or appropriate for DER
TSOs	(D) More market players are welcome to increase efficiency (B-R) Prequalification needs (B-R) Product definition (B-T) Observability of the DR as BSP (B-I/B) Resistance to incorporate DR in sensitive and more complex services (e.g. aFRR, FCR)
Legend: (D) Driver; (B-R) Barrier, Regulatory; (B-T) Barrier, Technological; (B-I/B) Barrier, Organizational/Behavioural; Level of agreement: (***) high, (**) medium	

Table 5.5: List of drivers and barriers for the consumer's electricity bill reduction and flexibility provision. Source: Lind et al. (2021a).

Flexibility provision through aggregation

In this BM, the aggregator (main actor) provides services to grid operators (DSOs and TSOs) by aggregating different types of DER, exploring the concept and possibilities of the VPP. This business model explores in particular the VPP in two forms, namely the Commercial Virtual Power Plant (cVPP), that provides services to the TSO (e.g. balancing markets), and the Technical Virtual Power Plant (tVPP), which provides local flexibility to the DSO. This BM was mostly discussed with independent aggregators and retailers (potential aggregators), the main actors in this business model, as well as regulators and TSOs.

The independent aggregator interviewed acknowledges that service provision to DSOs and TSOs will be a viable business in the future, but not in the short term. They mention the wide variation of national market rules and designs as an important barrier, which limits the potential scalability. In other words, lack of standardisation of market access interfaces is also a problem. Finally, they mention the need for real-time data to provide certain services (e.g. balancing).

Regulators see different barriers for the cVPP and the tVPP concepts. Regarding the former, they mention that balancing products are still not completely adequate for DR participation. Additionally, that the framework for independent aggregators is underdeveloped, and that revenues from balancing markets may be limited. Regarding the tVPP, the barriers identified by regulators are similar to the ones for the first BM (local flexibility procurement by DSOs). Firstly, the revenue regulation for DSOs is still CAPEX-based, and, secondly, local flexibility mechanisms are not in place yet, limiting the amount of flexibility that DSOs are willing/can procure.

The TSOs also mentioned the lack of role definitions for VPPs, BRPs and Balancing Service Providers (BSPs) as a barrier. In addition, they mention that VPPs may make the forecasting process more difficult, especially if these VPPs are large and resources are scattered across different regions.

Table 5.6 provides the final list of barriers and drivers identified in the interviews for this BM.

Stakeholders	Driver or Barrier
Retailers	(B-R) Uncertainty about how regulation is going to guide relationships between suppliers-aggregators-others
Regulators	(B-R) cVPP: Balancing products and procurement unfit for demand-side resources (B-R) cVPP: Undeveloped framework for independent aggregators (B-R) cVPP: Insufficient or uncertain revenues due to market conditions (B-R) tVPP: CAPEX bias in DSO revenue regulation (B-R) tVPP: Lack of local flexibility mechanisms (coordinated with grid tariffs) (B-I/B) cVPP: TSOs and DSOs used to operate without coordination (B-I/B) cVPP: Regulatory changes need to be progressive and carefully implement to avoid distorting the markets
Aggregators	(B-T) Need for real-time data for certain services (e.g. balancing) (B-T) Lack of standardization in markets access interfaces across Europe

continued ...

Stakeholders	Driver or Barrier
	(B-R) Wide variation in national market rules and design
TSOs	(D) More market players are welcome to increase efficiency (B-R) Role definitions for VPP, BRP, and BSP (B-R) Difficulty VPP may impose to TSO's forecasting
Legend: (D) Driver; (B-R) Barrier, Regulatory; (B-T) Barrier, Technological; (B-I/B) Barrier, Organizational/Behavioural; Level of agreement: (***) high, (**) medium	

Table 5.6: List of drivers and barriers for the aggregation (tVPP and cVPP). Source: Lind et al. (2021a).

5.2.3 Usage of Distributed Flexibility: the risk of a stalemate

In Valor et al. (2021), an analysis of the stakeholder consultation results is made from the optics of Service-Dominant Logic (S-DL). S-DL is a meta-theory of markets developed in the marketing and behavioral economics disciplines. The S-DL framework proposes that all transactions can be analysed from a services' perspective (e.g. provision of flexibility), as opposed to goods or products (e.g. provision of 1 MWh upward). This approach, i.e. the definition of services, along with actors, the integration of their resources, and the institutional arrangements in place, would result in the co-creation of value by all these elements combined (Vargo and Lusch, 2019).

The S-DLs framework can be a valuable tool to analyse the formation of markets for distributed flexibility (or the lack of). Considering that resource integration is a key factor for value co-creation, the stakeholder consultation conducted allowed for the identification of several key missing resources in five key categories, namely (i) physical, (ii) human, (iii), organisational, (iv) informational and (v) relational, as shown in Table 5.7.

	Physical	Human	Organizational	Informational	Relational
Consumers (industrial consumers)	Smart or interruptible equipment (e.g., smart fridges or heat pumps) that can be (de)activated following market demands for flexibility; Storage systems or self-production systems.	Personnel with energy expertise that can plan interruptible industrial operations.	Interruptible operational designs; Operations that can provide energy in the required blocks.	Research or studies demonstrating the positive outcomes (notably, economic) of providing flexibility to the grid; Methodology to measure and anticipate the return on the potential investments that consumers should do.	Trustworthy and cooperative relations with energy operators.
DSOs and TSOs	Platforms that can support the coordination of flexibility procurement and activation; Devices to ensure observability and controllability.	Personnel with skills and competences.	Organizational capabilities to manage the flexibility service; Revenues tied to grid reinforcement.	Studies demonstrating the financial return of potential investments.	Relational network between DSOs and TSOs.
Aggregators	Lack of standardization of market interfaces across countries.			Information about industrial consumers' energy consumption and management.	Limited network of relations among industrial consumers.

Table 5.7: Missing resources acknowledged by informants. Source: Valor et al. (2021).

The consultation also shows that regulators and policy-makers face barriers in providing the necessary institutional arrangement. Informants (i.e., regulators and policy-makers) acknowledge that existing regulatory dispositions, regulatory lacuna and regulators' limited responsibility in providing missing resources limit the potential for distributed flexibility exploitation. The interviews showed that regulators and policy-makers find barriers to changing existing institutional arrangements to enable the development of flexibility markets. First, the necessary changes are not straightforward, considering the complex interrelations between enabling flexibility markets and other policies and regulatory aspects (e.g., electricity tariffs). Second, they face uncertainty with regard to the system's reliability after the changes. It is important to note that they are also incentivised in different ways. While they are required to adopt EU regulations and look for economic efficiencies, maintaining reliability remains a larger incentive, which explains why regulators act in a risk-averse way. Finally, governance and organisational aspects may also pose challenges. Some inefficiencies sometimes influence the former in the sharing of competences between policy-makers and regulators. Moreover, regulators and policy-makers recognize having limited resources to implement the goals set up in the directives, notably in the ones mandates by the CEP. This directive places new responsibilities on regulators, but they are not allocated enough resources to carry them out as desired. Others claimed they would like to have more competences (e.g., enable pilots/sandboxes or provide guidelines for regulated tariff design). In sum, regulators and policy-makers describe a scenario in which they face difficulties in promoting the necessary adjustments to foster flexibility markets.

It is also important to consider that LFMs are policy-driven markets, and therefore, the lack of an appropriate institutional arrangements is a key barrier for fostering the acquisition and integration of the missing resources mentioned above.

5.3 Regulatory Landscape for Distributed Flexibility and TSO-DSO Coordination: a country assessment

5.3.1 EU Regulation on Distributed Flexibility and TSO-DSO Coordination

The European regulation has started including the concepts of distributed flexibility with the publication of the Network Codes and Guidelines in 2015. One of the objectives of the EBGL is "facilitating the participation of demand response including aggregation facilities and energy storage while ensuring they compete with other balancing services at a level playing field and, where necessary, act independently when serving a single demand facility" (Art. 3(f) - (European Commission, 2017b)).

However, most regulatory provisions for distributed flexibility appear with the publication of the CEP. First, the CEP initially establishes the flexibility procurement and network deferral logic for DSOs, including at the network planning stage.

Article 32 of the Electricity Directive establishes that DSOs should produce development plans that go through public consultation, are approved by regulators and that are made public (European Commission, 2019a). The objective of the network expansion plans is twofold. Firstly, that potential flexibility providers should have access to network information, so they can install DERs where it will be most needed. Secondly, DSOs should actively consider potential investment deferrals at the network expansion planning. Article 32(3) specifically mentions that "the network development plan shall also include the use of demand response, energy efficiency, energy storage facilities or other resources that the distribution system operator is to use as an alternative to system expansion" (European Commission, 2019a).

Several are the provisions for DSOs to not only be able to procure and use local flexibility but also to be incentivised to do so. The traditional incentive regulation in the EU, characterised by the “RPI-X”[2] approach, provides a clear incentive for OPEX reduction while usually incentivising the increment in CAPEX, as this component is the remunerated one by the Weighted Average Cost of Capital (WACC). This setting, as it is, provides little incentive for the use of local flexibility. Acknowledging this fact, the CEP states that “Member States shall provide the necessary regulatory framework to allow and provide incentives to distribution system operators to procure flexibility services, including congestion management in their areas, in order to improve efficiencies in the operation and development of the distribution system.” Moreover, “distribution system operators shall be adequately remunerated for the procurement of such services to allow them to recover at least their reasonable corresponding costs”(European Commission, 2019a).

The Electricity Directive highlights that this procurement should allow for DER participation and that it should be done “with transparent, non-discriminatory and market-based procedures unless the regulatory authorities have established that the procurement of such services is not economically efficient or that such procurement would lead to severe market distortions or to higher congestion.”. Therefore, it is important to note that the CEP does not provide clear incentive mechanism options, but rather that the need for incentives to be defined by the Member States. The second important conclusion is that the procurement of local flexibility should be done only when and where it proves to be more efficient than the business-as-usual operation.

Moreover, the Electricity Regulation of the CEP devotes Article 57 to the need for cooperation between TSOs and DSOs, including to "achieve coordinated access to resources such as distributed generation, energy storage or demand response that may support particular needs of both the distribution system operators and the transmission system operators" (European Commission, 2019b).

The Electricity Regulation also mandates the creation of the EU DSO Entity, a joint representative body for all the DSOs in the EU (previously represented by several associations). Among the tasks of the EU DSO Entity is to "cooperate with the ENTSO-E and adopt best practices on the coordinated operation and planning of transmission and distribution systems including issues such as exchange of data between operators and *coordination of distributed energy resources*" (Art. 55 2(b) - (European Commission, 2019b)). In addition, the EU DSO Entity should also participate in the drafting of distribution network codes (Art. 55 1(f) - (European Commission, 2019b)).

[2] The "RPI-X" approach is a typical incentive regulation schemes in which the DSO has an allowed regulatory revenue defined for a certain regulatory period (e.g. 3 to 6 years). The allowed revenue, however, is not fixed throughout the regulatory period. It is adjusted by the Retail Price Index (RPI) to account for inflation minus an "X" factor. The "X" factor, defined by the regulator, aims at pushing the DSO to find gains of efficiency. In this way, the DSO is forced to reduced costs during the regulatory period. Moreover, the DSO has incentives to reduce costs beyond the "X" factor, as any additional reduction in costs can be captured by the DSO.

In November of 2023, the EU DSO Entity and ENTSO-E started a public consultation on the draft of the Network Code for Demand Response (EU DSO Entity and ENTSO-E, 2023). The document provides important definitions towards fostering distributed flexibility and TSO-DSO coordination. With regard to the latter, Title VII is devoted to TSO-DSO coordination and DSO-DSO coordination. Several articles provide guidelines on DSO observability area[3], pre-qualification and data exchange. However, one important concept introduced by the Draft for TSO-DSO coordination is the DSO temporary limit. According to the Draft, DSOs may impose temporary limits on FSPs participating in other SOs' markets.

The Draft, however, is not prescriptive in most cases. Several aspects are still left to Member States when developing the National Terms and Conditions. For instance, the Draft proposes two different models of aggregation, one considering only the smart meter at the connection point, and the other considering data from sub-metering. The choice for one or the other is left to Member States (Art. 19(2) - EU DSO Entity and ENTSO-E (2023)).

Another important topic mentioned included in the Draft is the baselining of flexibility providers. Baselining is needed when the FSP does not have an individual schedule or commitment for consumption or production (e.g. residential consumer). The Draft establishes the principles for baseline definition, but the choices of individual methods, roles and responsibilities are left to the SOs and Member States. Appendix A provides an in-depth discussion on this topic, published in (Lind et al., 2024a).

5.3.2 Country Assessment

Despite the advancements being introduced by the different European regulations, the implementation of these measure on the different MSs may vary greatly. Several definitions are left to MSs as a complete standardisation in the EU might not be the most efficient solution[4], leading to the different interpretations by MSs and different implementation horizons. This can, to some extent, represent a risk for the full development of solutions and BMs such as aggregation and the exploitation of distributed flexibility.

This subsection presents an analysis of the regulatory conditions for distributed flexibility usage by SOs and the enhanced coordination between TSOs and DSOs. This subsection summarizes the work published in Cossent et al. (2022), and therefore considers regulatory aspects primarily until 2021. Despite the regulatory landscape being very dynamic in Europe, and possibly new regulation being already published in specific countries, this assessment is still valid to provide an overall perspective on the high-level issues regarding TSO-DSO coordination in the EU.

[3]The TSO observability area was already present in the EU Network Codes, and is now being proposed to DSOs. According to Art. 2(9) of the Draft, "'DSO observability areas' means the area constituted by the grid elements, grid users that might significantly affect existing or forecasted congestion issues or voltage issues in the DSO network. One DSO observability areas may cover parts of the grids from other systems operators, and overlap with other DSO observability areas linked to different issues."

[4]Balancing products are standard in the EU, considering that frequency control affects the whole integrated system, and that balancing products could be traded cross-borders. Products for DSOs, however, are aimed at solving local issues. Given the differences in institutional arrangements (e.g. different DSO landscapes in the EU, as shown in chapter 2 or infrastructure (i.e., different typologies in different countries, a standardisation for all the EU might bring inefficiencies. Also, hardly any cross-border trading of these products will be possible, and therefore gains from standardisation are limited in this sense too.

The methodology followed for this assessment is the following. First, a selection of six TSO-DSO use cases is made. A Use Case (UC), in the context of this chapter 5, is characterised by a pair of MM and flexibility services. The MMs are here defined as a single TSO or DSO flexibility market (e.g. LFM) or a CS market setting (e.g. Multi-level, Fragemented). The MMs considered are: (i) LFM (DSO exclusive); (ii) Central (TSO exclusive); (iii) Common CS (TSO-DSO coordination); (iv) Multi-level CS (TSO-DSO coordination); (v) Fragmented CS (TSO-DSO coordination); and (vi) Islanding (DSO exclusive); Flexibility services considered are: (i) congestion management (TSO, DSO); (ii) balancing (TSO exclusive); and (iii) voltage control (TSO, DSO). Table 5.8 provides a summary of the different UCs possible and the ones selected for this country assessment. Second, key regulatory topics are identified. For each of them, guiding research questions are formulated. Regulatory topics are also mapped against Use Cases.

Market Model / Service	Local	Central	Common	Fragmented	Multi-level
Balancing	*Not applicable*	**TSO procures balancing services from both transmission and distribution-connected providers.**	*Not applicable (although a common local CM and balancing market could be possible.)*	*Not applicable*	*Not applicable (although a local CM could forward bids to a balancing market.)*
Congestion Management	**DSO procures distributed flexibility to solve overloads.**	TSO procures CM services from both transmission and distribution-connected providers.	TSO and DSO have a common procurement for CM services from both transmission and distribution-connected providers.	**TSO and DSO procure CM services separately and maintain the scheduled power flow on the interfacing substation.**	**The DSO procures distributed flexibility for CM first in a LFM and forwards unused bids to the TSO.**
Voltage Control	DSO procures distributed flexibility to solve voltage issues.	TSO procures voltage control services from both transmission and distribution-connected providers.	**TSO and DSO have a common procurement for voltage control services from both transmission and distribution-connected providers.**	TSO and DSO procure voltage control services separately and maintain the scheduled power flow on the interfacing substation.	The DSO procures distributed flexibility for voltage control first in a LFM and forwards unused bids to the TSO.
Controlled Islanding	**DSO procures distributed flexibility during a period of outage (planned or unplanned).**	*Not applicable*	*Not applicable*	*Not applicable*	*Not applicable*
In bold: Selected Use Cases (UCs) for the regulatory country assessment.					

Table 5.8: Description of Use Cases considered for the regulatory country assessment.

Regulatory topics are organized in four big groups. First, topics related to the provision of flexibility by DER to TSOs are considered. In case of the TSO, markets and procedures for the provision of flexibility of transmission-connected units are already established. However, the participation of DER is still incipient. Second, the provision of flexibility by DER to the DSO is analysed. As established by the CEP, DSOs should be able to procure flexibility as a means of possibly deferring investments. For that to be possible, DSOs should be able to recover costs involved in the local flexibility procurement and have appropriate incentives to do so. Third, aggregation rules are looked upon, as aggregators (including independent aggregators) are expected to be an important enabler for flexibility provision by DERs. Finally, the current TSO-DSO coordination is considered, as a means to understand how advanced current coordination mechanisms are.

For each regulatory topic, a set of sub-topics is identified. For each sub-topic, a set of guiding questions are identified. These guiding questions will help steer the country assessment. Table 5.9 presents the final set of regulatory topics, sub-topics and guiding questions.

The regulatory questions proposed in Table 5.9 are answered for eight MS, namely: Austria, Belgium, Germany, Greece, Italy, Spain, Sweden, and The Netherlands[5].

Two main research sources were used when answering the guiding questions presented in Table 5.9. First, a questionnaire was circulated among professionals in the eight target countries. The questionnaire was an update on a previous regulatory survey published in Lind and Chaves Ávila (2019). In addition to the regulatory questionnaires, other sources also helped complement the information necessary for the analysis. In particular, the latest Survey on Ancillary Service Procurement and Balancing Market Design, by ENTSO-e and the Report on Regulatory Frameworks for European Energy Networks, by CEER (CEER, 2022; ENTSO-E, 2021b).

It is important to mention that the sources used as the basis for the analysis (both the regulatory questionnaire and the reports by CEER and ENTSO-e) have some caveats to their methodology. Firstly, they are a relatively high-level exercise, and not all details may be captured. Secondly, as mentioned by ENTSO-E (2021b), concepts used in different countries vary, posing a difficulty in the analysis when questionnaires are answered using a single set of definitions. Finally, answers are provided by individuals to the best of their knowledge. Answers cannot always be verified for correctness and/or completeness.

Following the identification of topics to be assessed in the different countries, a mapping of regulatory topics and both services and MMs is conducted. This mapping will serve to weight the assessment of countries in the different topics, providing the level of compatibility of services and MM. Regulatory topics are mapped against the different services, as shown in Table 5.10. The assessment is carried out by sub-topic and uses a rating from 0 to 5. This rating system aims at capturing the level of importance of one sub-topic to one service. Although the rating system is numerical, this remains a qualitative analysis, and the rating is a product of the discussion presented in the following paragraphs.

The provision of flexibility by DER to both TSO and DSO will have a high and direct impact whenever that SO is procuring the service in question. Therefore, when analyzing the provision of DER flexibility to balancing services, it is clear that "DER in Balancing" sub-topic has a high relevance, therefore being rated "5". The relevance of the remaining "DER provision of services"

[5] The selection of countries was partially done to represent participating countries from the Horizon 2020 CoordiNet Project. Nevertheless, they provide a good sample of MSs covering most regions of the continent.

Topic	Sub-topic	Quest. ID	Guiding questions
DER provision of services to TSOs	DER in Balancing	Q1	Can DER participate in balancing markets?
		Q2	Are there practical limitations to DER participation (e.g. min. bid size, symmetrical bidding)?
		Q3	Are all types of DERs allowed to participate in balancing markets?
	DER in Congestion Management	Q4	Can DER participate in congestion management markets?
	Voltage Control Mechanisms	Q5	Is voltage control a market-based service?
		Q6	Can DER provide voltage control?
DER provision of services to DSOs	DSO economic regulation and incentives	Q7	Does regulation provide cost recovery for flexibility procurement?
		Q8	Does regulation incentivize the use of flexibility (e.g. as an alternative for grid reinforcement)?
		Q9	Are there incentives for continuity of supply?
	Market-based procurement of flexibility by DSOs	Q10	Can DER provide services to the DSO in any form (e.g. non-firm connection agreement)?
		Q11	Is there regulation for market-based procurement of flexibility?
Aggregation rules	DER aggregation rules	Q12	Can DER be aggregated in the different markets (both TSO and DSO)?
		Q13	Is the independent aggregator recognized?
		Q14	Is there a comprehensive framework for independent aggregation (e.g. adequate rules on allocation of balancing responsibility)?
Current TSO-DSO coordination	TSO-DSO planning and operation coordination	Q15	What are the coordination measures in grid operation?
		Q16	Which is the information exchanged for grid operation? In which timeframes?

Table 5.9: Regulatory topics and guiding questions for country analysis.

Topic	Sub-topic	Balancing	Congestion Management	Controlled Islanding	Voltage Control
DER provision of services to TSOs	DER in Balancing	5	0	0	0
	DER in Congestion Management	0	5	0	0
	Voltage Control Mechanisms	0	0	0	5
DER provision of services to DSO	DSO economic regulation and incentives	0	5	5	5
	Market-based procurement of flexibility by DSOs	0	5	5	5
Aggregation rules	DER aggregation rules	2	2	2	2
Current TSO-DSO coordination	TSO-DSO planning and operation coordination	1	1	1	1

Table 5.10: Mapping of regulatory topics and services. 0-lowest relevance; 5-highest relevance.

sub-topics are rated low at "0", as they should not impact balancing directly. For congestion management, the "DER in (TSO) congestion management" is rated high, as well as the two sub-topics for the DSO. As most DSOs do not have local congestion management markets organized yet, we also consider the underlying requirements for DSOs to start procuring that service (e.g. economic incentives, cost recovery). In the case DSOs are already procuring local congestion management services, this is identified in the sub-topic "Market-based procurement of flexibility by DSOs". The service "controlled islanding"[6] is primarily a DSO service, and therefore it is rated high for the DSO and zero for the TSO, as the impact on the TSOs activity will depend on the MM. For this service, it is important the existence of output incentives on continuity of supply, as the islanding operation will contribute to the improvement of the DSO's indexes. Lastly, the "voltage control" is analyzed similarly to the congestion management service. It is a service that could be procured by both TSO and DSO, and therefore topics affecting its procurement are rated high for both SOs.

With regards to aggregation, this is rated "2" for all services, as aggregation can be considered an enabler for local flexibility provision and should affect them in a more homogeneous way. For some services, a higher or lower relevance rating could be debatable. Balancing markets, for example, usually have minimum bid sizes and technical requirements that limit the participation of

[6]The "controlled islanding" is characterised by the situation in which a section of the grid (e.g., a MV or LV feeder) is disconnected, resulting in an electrical island. This could be planned or unplanned. In this situation, the DSO, might use back-up generation, but in the future, DERs could also be used to power the electrical island. Lind et al. (2022a) shows that this service is viable, but the presence of ESS is critical. Also, economic aspects of this service should be further explored, such as the liquidity of such product.

smaller DER, making aggregation more relevant. However, as these aspects are already assessed in the "DER in Balancing" sub-topic, aggregation is also rated at "2" for balancing.

Finally, the topics related to TSO-DSO coordination are rated "1". These aspects will impact the markets models, discussed below. In isolation, considering only the services without a specific MM, the considerations on coordination schemes become less clear.

In Table 5.11, a similar exercise to the one presented in Table 5.10 is conducted. This time, the assessment is done for regulatory topics and MMs. This assessment is mostly guided by two main questions. First, who procures the service? Second, how independent is this procurement and activation by the DSO from the procurement/activation by the TSO (and vice versa)?

With regard to the first question, it is safe to say that a pure LFM will be impacted more by DSO-related regulation than TSO-related ones, especially if the LFM comes first in the market sequence. Conversely, the Central MM will be impacted mostly by TSO regulation. For the Common, Fragmented and Multi-level MMs, both TSO and DSO could procure flexibility[7].

Topic	Sub-topic	Local	Central	Common	Frag.	Multi-level
DER provision of services to TSOs	DER in Balancing	0	1	1	1	1
	DER in Congestion Management	0	1	1	1	1
	Voltage Control Mechanisms	0	1	1	1	1
DER provision of services to DSO	DSO economic regulation and incentives	1	0	1	1	1
	Market-based procurement of flexibility by DSOs	1	0	1	1	1
Aggregation rules	DER aggregation rules	1	1	1	1	1
Current TSO-DSO coordination	TSO-DSO planning and operation coordination	2	3	5	2	4

Table 5.11: Mapping of regulatory topics and market models. Assessment: 0-lowest relevance; 5-highest relevance.

The answer to the second question is less straightforward. One could argue that all MMs require a high degree of coordination between TSO-DSO. However, in order to find a common evaluation criterion, we look at the independence to which TSO and/or DSO can procure and activate DER flexibility in the respective MMs. Starting with the local MM, it could be assumed that the DSO could procure local flexibility with less interactions with the TSO than in other MMs. This could be especially true if the flexibility markets take place at the lower voltage levels

[7]Nevertheless, for this first question (who procures the service), ratings are kept as 1 or 0, as the biggest impact will be given by the TSO-DSO regulation topics. This way, when calculating the compatibility indexes in subsection 5.3.3, we avoid "double counting", considering the weights of regulatory topics by service.

in the distribution grid, leading to a small impact at the TSO-DSO interface. The Central MM would require a higher degree of coordination and/or information exchange. As the TSO procures flexibility connected at the distribution grid, the DSO could be impacted. To mitigate this, several options could be adopted. One example is to provide the TSO with the observability over the parts of the grid to which FSPs are connected (higher information exchange). Another option is to allow the DSO to double-check the foreseen flexibility activations, imposing limitations when needed (higher coordination). In the Common MM, the coordination and information could be even higher, as both TSOs and DSOs are procuring services through the same platform. This is also true for the Multi-level MM, in which flexibility markets are linked to each other. The Fragmented MM is the one in which coordination needs could be lower, even though both DSO and TSO are procuring flexibility. The reason for this is that the TSO does not have access to DER. Therefore, each SO only procures flexibility from resources connected at their respective grids. As identified in Delnooz et al. (2019), "there is no need for a very elaborate communication between the TSO and DSO [for the fragmented CS]. Coordination would mostly be limited to certain agreements on the exchanges between the TSO and DSO interconnections". With regards to the aggregation topics, the same rationale from Table 5.10 applies, and therefore it is rated "1" for all MMs.

In order to grade the target countries on different guiding questions, a scale from 0 to 5 is used. The definition of a specific grade is guided by regulatory conditions in Table 5.12. This exercise, although providing a quatification, remains purely quantitative.

Rating	*Description*
0	Regulation explicitly prohibits the analysed practice.
1	Regulation does not prohibit the analysed practice, but does not acknowledge it either.
2	Regulation acknowledges the analysed practice, but fails to provide any of the further definitions.
3	Regulation acknowledges the analysed practice and provides very limited definitions or are set to be defined in the future.
4	Regulation acknowledges the analysed practice and provides necessary definitions, but additional measures are necessary.
5	Regulation acknowledges the analysed practice, provides necessary definitions fully enabling its development.

Table 5.12: Exemplification of rating criteria for grading countries with respect to regulatory questions.

DER participation in balancing markets

On the one hand, balancing services are procured in what can be considered liquid and well-implemented markets in most countries. Products for this type of service are harmonized across Europe by the EBGL (European Commission, 2017b), and are now starting to be traded cross-border with the implementation of the European platforms for the exchange of balancing energy (ENTSO-E, 2022a). The different balancing products have different characteristics in terms of activation time and automatisation, limiting the potential for DER participation. However, the EBGL established that TSOs should allow the participation of DER in balancing markets.

The FCR is the primary frequency-regulation response, and therefore critical for the system. For this reason, several countries do not trade this service in an organized market, but rather consider it as a mandatory service for generation units able to provide it. The aFRR is the second frequency response to be activated. It is a fast reserve, and therefore units must comply with more complex requirements to be prequalified for the provision of this service. The mFRR is the reserve that follows, which substitutes the aFRR. This reserve has less strict communication requirements. Finally, the Replacement Reserve (RR) product, intended to serve as a replacement for the mFRR, is not in place in all countries. For this reason, it is not considered in this regulatory replicability analysis. Therefore, the focus of this section will be placed on the design of balancing markets for the provision of aFRR and mFRR products.

As of today, balancing markets across Europe are not fully harmonized, and therefore, specificities in every country matter in terms of replicability. Nevertheless, a harmonisation effort is taking place as a consequence of the implementation of the Network Codes and Guidelines. The Electricity Balancing Guideline calls for standardisation of balancing products to a certain extent. The main goal of the EBGL is to reach an integration of balancing markets across Europe. Within the scope of the EBGL are the pan-European balancing platforms that will trade the balancing products across borders, namely the PICASSO (for aFRR trading), the MARI (mFRR), and TERRE (RR). It is important to note though, that the standardisation proposed by the EBGL does not aim to be complete, but rather sufficient to allow cross-country trading between the different balancing markets. In practice, balancing markets will still differ among countries, and therefore, this regulatory replicability analysis is still relevant for the future scenario in which the EBGL will be fully implemented.

The review of the current situation in the above-mentioned countries shows that some relevant steps have been taken in order to adapt national balancing markets. However, it also revealed that further efforts would be required to ensure a level playing field for all potential participants in these markets. This review shows that simply enabling DERs to participate is not enough unless additional requirements and market conditions change as well.

Table 5.13 provides the country evaluation for each target country. The guiding questions are answered on a scale from 0 to 5, based on the rating criteria presented in Table 5.12. A more detailed discussion on the reasoning behind the grading of each country is found in Cossent et al. (2022).

DER participation in congestion management markets

Contrary to balancing markets, congestion management markets are considerably less harmonized across European countries with regards to internal congestions. The European electricity markets are based on bidding zones. While capacity between bidding zones is limited, power transmission within bidding zones should be, in principle, unrestricted. From a European regulatory perspective, cross-border congestion management is a harmonized process, guided by the Guideline on Capacity Allocation and Congestion Management (CACM) (EU, 2015). Internal congestions, however, are managed through different mechanisms by each TSO. The congestion management markets as proposed in chapters 3 and 4 are one type of remedial action at the disposal of the TSO to solve internal congestions. A remedial action is defined in Article 2(13) of CACM Guideline as "any measure applied by a TSO or several TSOs, manually or automati-

Q1	Can DER participate in balancing markets?			
Q2	Are there practical limitations to DER participation (e.g. min. bid size, symmetrical bidding)?			
Q3	Are all types of DERs allowed to participate in balancing markets?			

	Q1	*Q2*	*Q3*	*Short rationale*
Greece	1	0	0	DER cannot provide ancillary services. Updates to regulation are foreseen. Sources: Questionnaires.
Spain	4	3	5	DER can participate in balancing markets (aFRR, mFRR and RR). DR, DG, ESS and aggregators can participate. Minimum bid size and technical requirements may limit participation. Sources: Questionnaires, CNMC (2019b) and Cossent et al. (2020a).
Sweden	5	3	5	DER can participate in balancing markets. However, requirements (e.g. bid size) and prequalification requirements may limit participation. One product is set to have a minimum DR provision (the Strategic Reserve service) Sources: Questionnaires, Ribó-Pérez et al. (2021), Simon Färegård and Marko Miletic (2021), and smartEn (2021).
Austria	5	3	5	Balancing markets are open to DER and incentives exists for their participation. Prequalification process can be complex and communication requirements can be a barrier. Sources: Questionnaires, Cossent et al. (2020a) and smartEn (2018)
Belgium	5	5	4	DER can participate in FCR, aFRR and mFRR, Interruptible Service (DR exclusive), Strategic Reserve and the Capacity Remuneration Mechanism. Sources: Questionnaires.
Germany	5	4	5	DER can provide most balancing services and minimum bid sizes is 1 MW for most cases. Sources: Questionnaires.
Italy	2	2	2	DER can participate in experimental projects for balancing provision. Only aggregated units can participate. High metering and testing requirements still present a barrier to DER participation Sources: Questionnaires, Murley and Mazzaferro (2022).
The Netherlands	4	3	4	Balancing markets are open to DER participation, but practical limitations exist, such as symmetrical bids and high minimum bid sizes. Sources: Questionnaires, smartEn (2018).

Table 5.13: Assessment table for "DER in Balancing" sub-topic. Adapted from: Cossent et al. (2022).

cally, in order to maintain operational security." According to ENTSO-E, remedial actions may include redispatching, countertrading, topology changes, use of reactive power devices (e.g. tap-changers, capacitor banks etc), request (or control if available) additional voltage/reactive support from power plants, among others (ENTSO-E, 2015). This list of possible mechanisms is also in line with the definitions from the System Operation Guideline, Articles 20 to 23 (EU, 2017).

The list of possible remedial actions includes options that do not impose significant costs to the TSO, such as topology changes (ACER, 2021). Others are expected to generate costs to the TSO such as redispatching or countertrading. With regards to costly remedial actions, TSOs may use different mechanisms to solve internal congestions, one of them is a dedicated congestion management market, as considered in this Thesis. Apart from that, the TSO could also solve internal congestions by countertrading in the ID markets, meaning that the TSO procures energy in one location to sell the same amount in another location (Meeus, 2020). Finally, TSOs could use balancing bids to solve congestions. This could be considered a way of redispatching, as the TSO could activate one upward balancing bid in one location and a downward balancing bid in another location. In fact, the annual ENTSO-E survey on ancillary services and balancing market design shows that most countries use mFRR activations for purposes other than balancing, as illustrated in Figure 5.2.

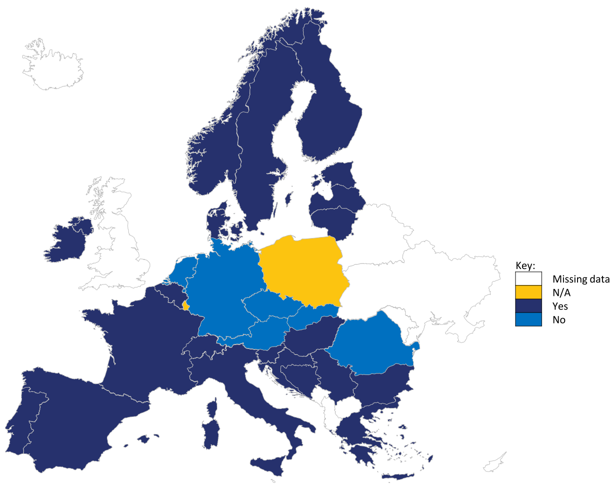

Figure 5.2: Answer to question 'Is it possible to use mFRR activations for purposes other than Balancing (e.g. congestion management)?'. Source: ENTSO-E (2021b).

Table 5.14 provides the country evaluation for the "DER in Congestion Management" sub-topic for each target country. A detailed discussion is presented in Cossent et al. (2022).

TSO's Voltage Control Mechanisms and DER participation

Although voltage control is not addressed directly on this thesis, this could also be a product procured by the TSO and the DSO from DERs.

Under the EU regulation terminology, the voltage control mechanisms are also a part of the remedial actions taken by the TSO to ensure secure operation of the grid. The SO Guideline classifies "control voltage and manage reactive power" as one of the categories of remedial actions. The

Q4	Can DER participate in congestion management markets?	
	Q4	*Short rationale*
Greece	0	DER cannot provide congestion management services. Sources: Questionnaires.
Spain	2	Only DER scheduled in the DA market (in principle connected to the HV grid). Sources: Questionnaires, CNMC (2022).
Sweden	2	DER can provide congestion management services, but mFRR bids are used. Sources: Questionnaires.
Austria	1	Only for emergency purposes. Sources: Questionnaires.
Belgium	0	DER cannot provide congestion management services. Sources: Questionnaires.
Germany	3	DER can provide congestion management depending on local requirements. Sources: Questionnaires.
Italy	2	DER can provide congestion management under pilot projects. Sources: Questionnaires.
The Netherlands	4	DER can provide congestion management services to the TSO through the GOPACS platform. Sources: Questionnaires, Valarezo et al. (2021).

Table 5.14: Assessment table for "DER in Congestion Management" sub-topic. Adapted from: Cossent et al. (2022).

SO Guideline includes options that are not costly to the TSO and others that could be organized as a remunerated service.

The ENTSO-E's survey on ancillary services shows that for the countries under analysis, only Belgium and The Netherlands declared to have some sort of market-based procurement of voltage control-related services (ENTSO-E, 2021b). With regards to which types of providers can participate in this market, only Germany mentioned RES and storage, which could be a DER. No country allows the participation of DR or independent aggregators. When asked about the settlement rules, Austria, Belgium and The Netherlands mentioned a concrete type of remuneration settlement, suggesting that voltage control in other countries could be not remunerated (e.g. Germany) (ENTSO-E, 2021b).

Table 5.15 provides the country evaluation for the "TSO's Voltage Control Mechanisms" sub-topic for each target country. A detailed discussion is presented in Cossent et al. (2022).

DSO economic regulation and incentives

Nowadays, most European countries have implemented some form of incentive regulation (e.g. RPI-X), which intends to promote cost reductions whilst ensuring adequate levels of security of supply. In spite of the many differences in the details of the national regulatory frameworks that can be found, some general features that discourage the use of flexibility are widespread. These create a situation where current regulation is generally still poorly adapted to this upcoming paradigm of replacing or deferring investments through the use of distributed flexibility.

The way the incentive regulation is set also matters. It is traditionally set either over the OPEX alone (letting the CAPEX be a pass-through component), or over the TOTEX. Historically, the

Q5	Is voltage control a market-based service?		
Q6	Can DER provide voltage control?		
	Q5	*Q6*	*Short rationale*
Greece	1	0	Voltage control is mandatory. No DER participation. No settlement mentioned.
Spain	1	0	Voltage control is mandatory. No DER participation. No settlement mentioned.
Sweden	1	0	Voltage control is mandatory. No DER participation. No remuneration to providers.
Austria	2	0	Voltage control is mandatory. No DER participation. Marginal pricing used (remuneration in place).
Belgium	4	0	Voltage control is a market-based service. No DER participation. Remuneration in place.
Germany	1	2	Voltage control is mandatory. RES and storage can provide voltage control. No settlement mentioned.
Italy	1	0	Voltage control is mandatory. No DER participation. No settlement mentioned.
The Netherlands	3	1	Voltage control is a "hybrid" service. RES can provide voltage control. Pay-as-bid used (remuneration in place).
Sources used for all countries: Questionnaires and ENTSO-E (2021b).			

Table 5.15: Assessment table for the "Voltage Control" sub-topic. Adapted from: Cossent et al. (2022).

former setting was firstly adopted, providing the signal to DSOs to build a strong network (investments were incentivised, as they are the ones remunerated) and providing an incentive to reduce inefficiencies in the management of the companies. However, in the perspective of a high penetration of DER and the possibility of such resources providing flexibility as a means to avoid reinforcement, this CAPEX-biased type of regulation ends up providing an incentive in the opposite direction.

In addition to the CAPEX/OPEX treatment, economic regulation may also include additional components to the DSO's revenue formula in order to provide target-specific incentives. A widely used example is the incentive to reduce losses. This can be done by including a bonus (or penalty) to the remuneration, by obliging the DSO to buy their own losses. Additionally, quality of supply can be incentivised, also by providing bonus/penalties based on pre-established indicators. The latter can be especially important for the controlled islanding service. Naturally, incentives for SOs should be carefully crafted so they do not become perverse or affect negatively other necessary features of system operation, such as system security and reliability. For this, an integrated analysis is necessary, considering all aspects and incentives given to SOs.

Table 5.16 displays the rating attributed to each country for each question on the "DSO economic regulation" sub-topic[8].

[8]For this sub-topic, not enough information was collected for Belgium, Italy and The Netherlands. For these countries, a score of 2.5 was attributed for the purposes of the calculation of the compatibility indexes calculated in section 6.2. This number is slightly below the average of the other countries and is chosen in other no to pollute the calculations while still ensuring that the scores can be calculated for all use cases.

	Q7	Does regulation provide cost recovery for flexibility procurement?		
	Q8	Does regulation incentivise the use of distributed flexibility?		
	Q9	Are there incentives for continuity of supply?		
	Q7	*Q8*	*Q9*	*Short rationale*
Greece	2	2	0	Incentive regulation, but with a traditional OPEX/CAPEX differentiation. Some incentives exist to promote the use of flexibility. No incentives for continuity of supply.
Spain	2	1	4	Incentive regulation, traditional OPEX/CAPEX differentiation. No clear incentives to use flexibility yet. Bonus-malus incentive over continuity of supply indexes.
Sweden	3	3	4	CAPEX regulation provides some incentive to cost reduction. Incentives exists for flexibility usage (subscription limits). Bonus-malus incentive over continuity of supply indexes.
Austria	3	1	3	Separate OPEX/CAPEX regulation, but with a TOTEX benchmark before every regulatory period. No clear incentives for the procurement of flexibility. Limited financial incentives on continuity of supply.
Germany	4	1	4	TOTEX incentive regulation is used. No clear incentives for the procurement of flexibility. Bonus-malus incentive over continuity of supply indexes.
Sources used for all countries: Questionnaires and CEER (2022).				

Table 5.16: Assessment table for "DSO economic regulation" sub-topic. Adapted from: Cossent et al. (2022).

Market-based procurement of flexibility by DSOs

In this subsection we analyse the existence of specific regulation on the possibility for DSOs to procure local flexibility, in line with the definition brought forward by the CEP. These local flexibility mechanisms can take different forms depending on the procurement method, the participating technologies, whether participation is mandatory or voluntary, etc. According to CEER (2018), four general types of flexibility mechanisms can be found. In this section we focus on specific implementations on the "Market-Based Procurement" type.

i Rule-based: Mandatory requirements set by regulation.

ii Network Tariffs: incorporating flexibility incentives (Time-of-Use, dynamic charges, etc.).

iii Connection Agreements: DSOs reach an agreement with new grid users who provide flexibility in exchange for some sort of compensation (e.g. lower connection charges).

iv Market-Based Procurement: DSOs explicitly procure flexibility from local markets. In this section we focus on specific implementations on the "Market-Based Procurement" type.

Table 5.17 provides the country evaluation for the "Market-based procurement of flexibility by DSOs" sub-topic for each target country. A detailed discussion is presented in Cossent et al. (2022).

DER aggregation rules

The independent aggregator is a new agent defined by the CEP as a "market participant engaged in aggregation who is not affiliated to the customer's supplier" (European Commission, 2019a). In this context, DERs, including demand response, can enter in an agreement with an independent aggregator besides already having an agreement with a retailer. Moreover, the CEP also determines "the right for each market participant engaged in aggregation, including independent aggregators, to enter electricity markets without the consent of other market participants" (European Commission, 2019a). That means that, in principle, an independent aggregator does not have to enter into an agreement with the consumers' retailer, and that can lead to distorting situations if a proper regulatory framework is not in place. For instance, the independent aggregator can create an imbalance on the retailer's portfolio by activating their customer's flexibility. If there is no compensation in place, the retailer is worse off. On the contrary, if there is a mandatory compensation in place, that may put the independent aggregator in a position of uncertainty regarding the retailer's profile and the baseline for the deviations, leaving the independent aggregator business model at risk (Lind et al., 2019a).

On the ensuing, the questions of whether aggregation is permitted, particularly considering DER, and whether regulatory conditions are suitable for the development of independent aggregators will be explored for the countries considered in this report.

Table 5.18 provides the country evaluation for the "DER aggregation rules" sub-topic for each target country. A detailed discussion is presented in Cossent et al. (2022).

Q10	Can DER provide services to the DSO in any form?		
Q11	Is there regulation for market-based procurement of flexibility?		
	Q10	*Q11*	*Short rationale*
Greece	3	3	A new regulation was published recently allowing for the DSO to procure distributed flexibility, although not yet applied. Sources: Questionnaires.
Spain	2	2	No regulation specifically on local flexibility. Pilots and a sandbox regulation published. DSOs can request large DER flexibility in some cases. Source: Questionnaires, CNMC (2022).
Sweden	4	1	No regulation specifically on local flexibility. A large pilot projects exist. A natural incentive to use flexibility by DSOs exists (subscription levels, as discussed in Chapter 3). Sources: Questionnaires, Lind and Chaves Ávila (2019).
Austria	1	1	No regulation specifically on local flexibility. Sources: Questionnaires.
Belgium	2	1	Local flexibility can be used, although not remunerated. Sources: Questionnaires.
Germany	3	1	No regulation specifically on local flexibility. Large scale projects are testing local flexibility provision to DSOs. Sources: Questionnaires, Valarezo et al. (2021).
Italy	2	1	No regulation specifically on local flexibility. A sandbox regulation was recently published. Sources: Questionnaires.
The Netherlands	3	1	No regulation specifically on local flexibility. Large scale projects are testing local flexibility provision to DSOs (GOPACS). Sources: Questionnaires, Anaya and Pollitt (2021) and Valarezo et al. (2021)

Table 5.17: Assessment table for "Market-based procurement of flexibility by DSOs" sub-topic. Adapted from: Cossent et al. (2022).

Q12	Can DER be aggregated in the different markets (both TSO and DSO)?			
Q13	Is the independent aggregator recognized?			
Q14	Is there a comprehensive framework for independent aggregation (e.g. adequate rules on allocation of balancing responsibility)?			

	Q12	*Q13*	*Q14*	*Short rationale*
Greece	4	4	1	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. No comprehensive framework in place. Source: Questionnaires.
Spain	3	3	1	Aggregation (including independent) is possible. However, aggregation cannot include different types of DER. No comprehensive framework in place. Source: Questionnaires.
Sweden	4	4	1	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. No comprehensive framework in place. Source: Questionnaires, Bertoldi et al. (2016).
Austria	4	4	1	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. No comprehensive framework in place. Source: Questionnaires.
Belgium	4	4	4	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. A comprehensive framework exists. Source: Questionnaires, Bray and Woodman (2019), ELIA (2019), Elia (2019), Kraftwerke (2019), and smartEn (2018).
Germany	4	4	4	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. A comprehensive framework exists. Source: Questionnaires, Next Kraftwerke (2017) and smartEn (2018).
Italy	4	4	1	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. No comprehensive framework in place. Source: Questionnaires, smartEn (2018).
The Netherlands	4	4	1	Aggregation (including independent) is possible. An agreement aggregator-BRP is in principle necessary. No comprehensive framework in place. Source: Questionnaires.

Table 5.18: Assessment table for "DER aggregation rules" sub-topic. Adapted from: Cossent et al. (2022).

Current TSO-DSO coordination for grid operation

Currently and historically, TSOs and DSOs have already been in close coordination for the operation and often for the planning of the grid. In order to evaluate the current level of coordination, the survey focused on the information currently being exchanged by TSOs and DSOs at all operational timeframes, i.e, long-term, day-ahead, near real-time, real-time, and ex-post. According to respondents, in most countries TSOs and DSOs exchange information on all timeframes. An exchange of forecasts of schedules at the interfacing substations is a common practice for instance, as mentioned by respondents from Greece, Sweden, Spain, The Netherlands and Germany for the Day-ahead timeframe (Cossent et al., 2022). In Greece, the DSO must inform the TSO in case of a reconfiguration that can lead to a load reduction of more than 10 MW on the interfacing substation. Details on the specific information exchange for each country can be found in Lind and Chaves Ávila (2019) and Cossent et al. (2022).

Table 5.19 displays the rating attributed to each country for each question on the "Current TSO-DSO coordination" sub-topic.

5.3.3 Compatibility of Use Cases

Considering the evaluation of each sub-topic and the mapping of relevance for the different services and MMs, a final compatibility assessment is made for the different countries and for different Generic UC (composed of a pair of service-MM). In order to do that, the scoring attributed to each guiding question is weighted according to the coefficients presented in Table 5.10 and Table 5.11. The formula for the calculation of the compatibility index is shown below. The Compatibility Index is a measurement (from zero to five) that helps understand how compatible the current national regulatory framework is to a determined UC. An index closer to five means that the current national regulation is more welcoming to the development of that UC. Conversely, an index closer to zero means that regulation still prevents the development of that UC. Colors/indexes in between mean that regulation may allow the UC to be developed, but it is incomplete and does not provide the necessary conditions for the different actors. However, as mentioned at the beginning of this Section, the Compatibility Index is a tool for the qualitative analysis, and not a quantitative evaluation for the different countries. This remains a qualitative analysis, and the Compatibility Indexes calculated next are a product of the discussion presented in the previous sub-sections.

$$Compatibility_{country,UC} = \frac{\sum_{question}\left[(Score^{country}_{subtopic} \cdot Weight^{service}_{subtopic} \cdot Weight^{MM}_{subtopic}\right]}{\sum_{subtopic}\left[(Weight^{service}_{subtopic} \cdot Weight^{MM}_{subtopic}\right]} \tag{5.1a}$$

, where

$Compatibility_{country,UC}$ is the compatibility index calculated for $country$ in the Generic Use Case UC,

Q15	What are the coordination measures in grid operation?		
Q16	Which is the information exchanged for grid operation? In which timeframes?		
	Q15	*Q16*	*Short rationale*
Greece	2	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post. Source: Questionnaires.
Spain	2	2	TSO and DSO exchange information in all timesteps of the operational planning, real-time and ex-post. DSO can limit activations by the TSO. Sources: Questionnaires, CNMC (2019a).
Sweden	2	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post. Sources: Questionnaires, Wallnerström et al. (2016).
Austria	2	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post. Source: Questionnaires.
Belgium	2	1	Coordination and information exchange takes place mainly during prequalification. Source: Questionnaires.
Germany	2	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post. Source: Questionnaires.
Italy	2	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post. Source: Questionnaires.
The Netherlands	4	2	Coordination and information exchange takes place in every timestep of the operational planning, real-time and ex-post. Advanced TSO-DSO coordination takes place through the GOPACS platform. Sources: Questionnaires, Valarezo et al. (2021).

Table 5.19: Assessment table for "Current TSO-DSO coordination" sub-topic. Adapted from: Cossent et al. (2022).

$Score^{country}_{subtopic}$ is the average score given to the regulatory $subtopic$ in the specific $country$ (Tables 5.13 to 5.19),

$Weight^{service}_{subtopic}$ is the weight for the specific $service$ (Table 5.10), and

$Weight^{MM}_{subtopic}$ is the weight for the specific MM (Table 5.11)

For this compatibility analysis, six UCs were chosen. Each UC is composed of one service and one specific MM. The UCs are:

- Local (MM) Congestion Management (Service)
- Multi-level (MM) Congestion Management (Service)
- Central (MM) Balancing (Service)
- Local (MM) Controlled Islanding (Service)
- Fragmented (MM) Congestion Management (Service)
- Common (MM) Voltage Control (Service)

Figure 5.3 shows that among the different countries, a consistency exists on the potential for implementation of the different UCs. This is mostly driven by how open markets are to DER participation and the levels of incentives and possibilities for the TSO and DSO to procure that flexibility. Among the different UCs, slight differences exist, either driven by the service or the MM chosen. The most implementable UC seems to be the "Central Balancing" (average 3.06). The balancing service is highly harmonized across Europe, and the opening of this service to DER is mandated by the Network Codes and implemented in many countries. On the opposite side, with the lowest average index, is the "Common Voltage Control" (average 2.04). Although the MM is still the same, the service is far less harmonized, and for several of the countries analysed, it is not a market-based service, but a mandatory one provided by conventional units, often not remunerated. Other UCs capture differences in the MM implementation, as is the case for the UC on local congestion management and multi-level congestion management. It is possible to observe that the overall compatibility index is slightly lower for the multi-level when compared to the local MM, due to higher need for TSO-DSO coordination.

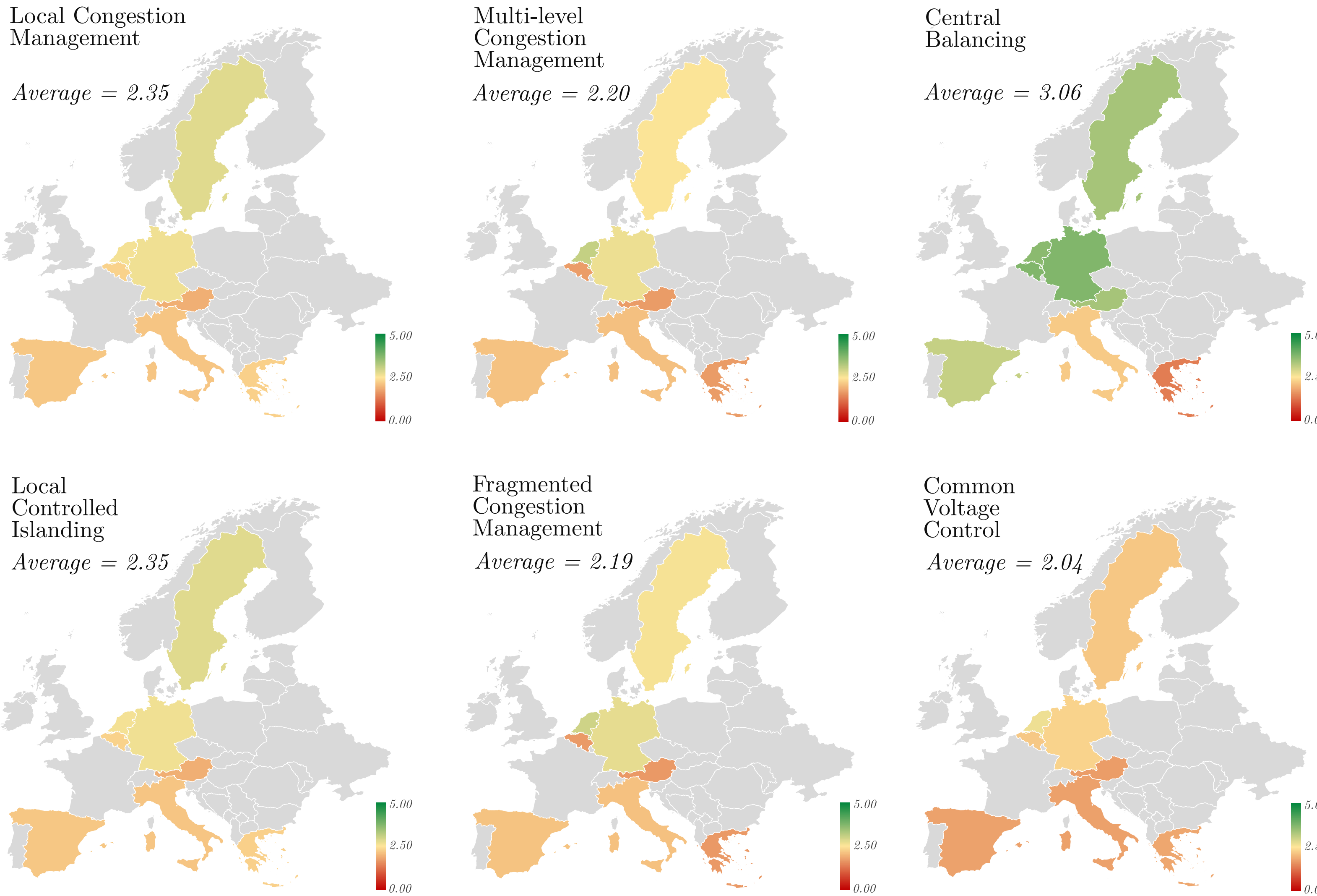

Figure 5.3: Regulatory Compatibility of Selected Generalized Use Cases. Source: Cossent et al. (2022).

5.4 Conclusions

In this chapter, a broad qualitative analysis of the conditions for enhanced TSO-DSO coordination is conducted. The starting point for this discussion is the fact that TSOs and DSOs will have to coordinate more closely, especially due to the integration of distributed flexibility in current and future electricity markets[9]. The analysis conducted is two-fold. First, the perception of stakeholders on different BMs is captured in the consultation and analysed. Second, a regulatory assessment in eight EU MSs is carried out.

The stakeholder consultation allowed for a myriad of concerns to be identified on different flexibility-related BMs. Although the focus of this thesis is on the actual TSO-DSO coordination mechanisms, these mechanisms will only be put in place if this flexibility-related BMs are finally deployed. This involved the possibility for aggregators (including independent ones) and data companies to develop innovative BMs, for end-user to perceive flexibility provision as a viable activity, and for SOs to have the incentives to use this distributed flexibility. The analysis showed that the number of barriers identified by stakeholders vastly surpasses the number of drivers, showing important concerns from all stakeholders - from consumers to regulators. The analysis of this stakeholder consultation through the S-DL framework sheds further light on the problem. Flexibility usage and markets are policy-driven markets. Therefore, the integration of the missing resources is partially due to lack of appropriate institutional arrangements and the difficulties in developing them. Regulators and policymaker too, have limited resources, while having to implement comprehensive changes in the SOs' regulatory frameworks.

These findings lead to the second part of this chapter, namely the assessment of the current conditions for flexibility procurement under different UCs (here defined as a pair of MM and flexibility service). Although this qualitative exercise is challenged by several methodological aspects (i.e., data collection, comparability, and assessment), it is an exercise towards understanding the regulatory issues that will have to be addressed in the coming years. The country analysis showed that opening the existing distributed flexibility markets (e.g., balancing) is currently the mostly implementable UC, followed by DSO-exclusive flexibility markets (i.e., LFMs for congestion management or islanding). It is important to mention that in this MMs, coordination is not envisioned or it is very limited. That would be a scenario, for example, in which DERs connected at HV level are able to provide balancing services and a LFM is created to solve congestions at a MV feeder. When CSs are considered, implementability decreases not only due to the challenges posed by CSs, but also by the flexibility services. The country analysis reveled that intra-bidding zone congestion management follows unharmonised and non-transparent practices in Europe. This is a clear challenge to the implementation of the Fragmented or Multi-level CSs vastly researched in the TSO-DSO literature and this thesis. Voltage control is another service in which organised markets are the exception, not the norm.

This chapter also opens future research avenues. On the one hand, future work could study actors who have participated in the stakeholder consultation to examine how the anticipated barriers have been removed or navigated. Moreover, a larger set of participants in different countries could also shed light to other barriers not previously identified. Likewise, the regulatory assess-

[9] Many other reasons for future enhanced TSO-DSO coordination exist. However, the focus of this thesis is on the coordination for the efficient flexibility procurement and activation. Other reasons, as identified in chapter 2 (e.g., coordinated network planning) are not addressed in detailed in this thesis, and consequently, in these conclusions.

ment could be expanded to other countries, but could also be repeated on the countries analysed in this study to understand how, when and if barriers are being removed. This temporal dimension, often neglected in regulatory studies, has the potential to reveal the dynamics behind the adoption of regulation for different topics.

6 Conclusions, Contributions and Future Research

This chapter summarises and discusses the main conclusions from this thesis in an integrated way. It also presents the original contributions provided by this thesis and the list of publications derived from this work. Finally, future lines of research are identified.

This thesis proposed a multidimensional study utilising both qualitative and quantitative methods, including several different facets of the TSO-DSO coordination research field. This thesis included the modelling of coordination schemes, both from a real-world perspective (Chapter 3) as well as from a game-theoretical perspective (Chapter 4). It also included the qualitative analysis of regulatory conditions for TSO-DSO coordination in Europe and the implications of new business models for this coordination (Chapter 5). All thesis studies resulted in findings on their own. However, in order to try to answer the research questions posed by Chapter 1 and assess the contributions made to the state-of-the-art mapped in Chapter 2, integrated conclusions are needed. This integrated discussion is therefore made in the section section 6.1. The remainder of this chapter also details the original contributions in section 6.2, lists the publications derived from this thesis in section 6.3 and, finally, identifies the future lines of research in section 6.4.

6.1 Summary and conclusions

This thesis started from the observation that power systems are changing in ways that pose both challenges and opportunities to SOs. One the one hand, TSOs have to deal with a higher share of intermittent generation from RESs, while DSOs are called to actively manage distribution grids and to integrate distributed energy resources, which are progressively more present in the networks as a response to decarbonisation and consumer-empowerment efforts. While these changes might be seen as challenges, opportunities also arise. Both TSOs and DSOs will be able to use the flexibility to be offered by DERs. TSOs will be able to have higher liquidity in their existing markets (e.g. balancing, congestion management), while DSOs will be able to procure distributed flexibility to solve distribution constraints (e.g. overloads, voltage problems). In this context of shared interest on the flexibility from DERs, however, arises the need for enhanced TSO-DSO coordination, the topic of this thesis.

The TSO-DSO coordination is a research field that spans several research domains. Naturally, this thesis had to focus on a tractable set of research domains and objectives. Therefore, this thesis focused on the research of Coordination Schemes (CSs), their modelling, applications, and the regulatory aspects of their implementation. A choice was also made in this thesis to cover a set of research domains. Instead of investigating one single gap in the literature, this thesis tried to provide contributions (although initial and in need of future research) to a few of them. Therefore, it seems reasonable to organise these overarching conclusions per literature gap, as they are identified in the conclusions of Chapter 2.

Therefore, the remainder of this section is organised in four subsections. Subsection 6.1.1 discusses the DER integration in balancing and local congestion management markets. Subsection 6.1.2 summarises contributions to the field of coordination schemes. Subsection 6.1.3 addresses transmission-distribution optimisation models while subsection 6.1.4 comments on data management and exchange.

6.1.1 DER integration in balancing and local congestion management markets

The integration of DERs into balancing and congestion management markets precedes the effort to enhance TSO-DSO coordination for distributed flexibility procurement. Chapter 5 showed that are important structural and regulatory barriers to be transposed so that distributed flexibility can be exploited. Both buyers (SOs) and sellers (customers) are in need of incentives in order to make their flexibility-related activities viable. Also, enabling actors also need to be able to develop their activities, such as aggregators.

The regulatory process plays an important role in providing the necessary conditions for the exploitation of distributed flexibility. Chapter 5 shows that Local Flexibility Markets (LFMs) are policy-driven markets, and therefore need an appropriate institutional arrangement. On the other hand, however, Chapter 5 also shows that European countries are lagging on establishing the necessary regulatory frameworks. For instance, it is not defined how incentives, remuneration and risk allocation will work for DSOs when using distributed flexibility. TSOs, on the other hand, mostly solve internal congestions with processes other than organised markets. These regulatory definitions and harmonisation efforts will be required not only for high-level changes in SOs' regulation, but also to lower-level ones, such as defining how the baselining of distributed flexibility will be made, for example (as shown in Appendix A). Only when most of these barriers are overcome, actors will have a higher regulatory certainty to exploit their business models, as revealed by stakeholder in consultation of Chapter 5. Of course, other barriers do exist, such as technological and ICTs ones, which lay outside the scope of this thesis.

In this thesis, the benefits of integrating DERs were also shown quantitatively, especially in Chapter 3. By modelling realistic case studies of one year in two countries, this thesis could produce real-world results that indicate the potential benefits (and eventual risks) of higher penetration of DERs. First, it was shown that having a small amount of distributed flexibility (e.g. 10 GWh in the Swedish case) , DSOs could incorporate a large amount of additional demand (145 GWh, 10% of the annual demand) just using flexibility and without incurring in Non-Served Flexibility (NSF) (a concept introduced in this thesis). The results have also shown the benefits of not only having more flexibility, but also diverse types of flexibility providers. Considering that different types of DERs have different flexibility capabilities, SOs will benefit the most by having a mix of different types.

Chapter 3 also showed the intertwined roles of DERs as both participants in wholesale energy markets and flexibility markets and how this affects SOs. This means that by increasing DER penetration, adverse effects can also be created. The Spanish case showed this, when only DG is increased in an already wind-saturated network, leading to higher costs to the TSO, eventually. The opposite effect, however, was verified in the Swedish case. By adding DG in a network in need for upward flexibility, DSO's cost are reduced without the need for flexibility activation. This showcases the need for integrated modelling analysis in real-world flexibility-related issues, considering a full market sequence as proposed in chapter 3.

6.1.2 Coordination Schemes Between TSO and DSO for the Procurement of Flexibility

A key objective of this thesis was the identification of efficient Coordination Schemes (CSs) for the procurement of distributed flexibility. This topic proved to not have a single straightforward answer such as the best CS to be adopted in TSO-DSO coordination. The first complicating factor is that there is not one single TSO-DSO coordination, but rather several types. Chapter 2 shows that the characteristics of TSOs and DSOs change considerably from country to country. The review also showed that in Europe, the most common TSO-DSO interfacing substation is at the EHV-HV voltage levels. This means that both SOs operate meshed network, departing from the typical assumption in CS modelling of a meshed transmission network and a radial distribution network. Therefore, adaptations on the modelling of CSs were proposed to better represent this meshed-to-meshed topology observed in Europe.

This thesis has mostly focused on the modelling on three CSs, namely, the (i) Common CS, the (ii) Multi-level CS and the (iii) Fragmented CS. The Multi-level was prioritized in chapter 3 while the Fragmented in chapter 4. The Common CS was present in both, also as a first-best benchmark for the other CSs. It became well understood both in the literature and through results of this thesis that the Common CS leads to the lowest cost in flexibility activation. This result is not only shown in the results of chapter 3 and 4, but it is also intuitive: one single optimisation can handle all constraints at once, leading to optimality. The market splitting process will introduce inefficiencies due to the imperfect information sharing process.

The Multi-level CS is designed in such a way that unused bids are passed on from the DSO to TSO. In chapter 3 it is shown that the DSO has to forward unused bids, but should also validate that forwarded bids do not cause problems to the distribution grid. In the case of chapter 3, for instance, forwarded bids cannot be activated in the direction that would cause more congestions to the DSO. For example, if the DSO is procuring upward flexibility in the LFM to clear an overload on a transformer, the TSO should not activate downward bids downstream of that transformer for balancing. The solution of DSO posing limitations is a simple and secure way to allow for the Multi-level CS to be implemented. However, from an efficiency perspective, it is not always perfect, especially in a meshed-to-meshed context in which validation is not so straightforward. One possible solution could be a more detailed information exchange, such as the Feasibility Region field of research suggests. This method, however, also has implementation problems highlighted in chapter 2 (e.g., the DSO acts as an aggregator). The Fragmented CS is, on the other hand, even more conservative, as it requires SOs to only use DERs connected to their own grids and requiring them to maintain the power flows over the interfacing substations as scheduled (i.e., any flexibility market has to be a complete redispatch market withing the SO's borders). This may prevent the most economical FSPs to be activated.

Not only market splitting with imperfect information sharing increases system's costs, but it also leads to cost allocation distortions. Let us consider the Multi-level CS. In a LFM, a DSO activates upward flexibility to clear the overload on a transformer. Following that, the DSO forwards unused and validated bids to the TSO. Assuming that the TSO does not have any need for flexibility in their markets (neither balancing or congestions), the TSO will now have to activate the amount of flexibility used by the DSO in the opposite direction, bearing that cost for a problem originated in the distribution grid.

Recent research showed that both problems with disjoint CSs can be solved by properly pricing the change on the interface flow. The price for the interface flow provides both an optimal information for efficient flexibility activation and for cost allocation. Therefore, when optimally priced, both the Multi-level CS and the Fragmented CS would lead to the same result as the Common CS. However, the literature has not shown that computing the optimal interface flow price is not a trivial process.

Chapter 4 is devoted to this problem. However, it aims at providing a regulatory second-best instead of an algorithmic way to compute interface flow prices (proven to be hard by the literature). Chapter 4 first considers what TSOs would do in a hypothetical scenario in which they can set interface prices freely and strategically (as they have the first-mover advantage). In this case, it was shown that the TSO will exploit their position and create important cost allocation distortion in their favour, especially if the DSO's LFM is low in liquidity. However, a surprising effect is that the TSO, when acting upon incentive, activates (or leads to the activation of) economical FSPs. Therefore, when compared to the Common CS, the FSPs activated are similar, only that undesirable transfers are created from the DSO to the TSO. Based on this observation, different regulatory mechanisms were tested, aiming at still providing some incentive to TSOs, but limiting unwanted cost allocation distortions. The cap and floor solution proposed in this thesis compared favourably against the vanilla implementation of the Fragmented CS and other regulatory mechanisms found in the literature.

Therefore, this thesis points in the direction that a regulatory interface pricing mechanism could allow for the efficient implementation of a disjoint market design CS such a the Multi-level or Fragmented. The mechanism proposed is not supervision-intensive for regulators, allows for a second-best in terms of system's cost and cost allocation, and is minimal in information exchange (only interface prices are exchanged).

6.1.3 Transmission-Distribution optimisation models

Chapter 2 identified the need for advancements in optimisation modelling mostly for the operational purposes. In other words, models to be implemented in actual market design algorithms. This thesis, however, did not investigate this type of modelling in depth. The models from chapter 3 and 4 are mostly for research purposes. However, a few contributions were made in the field of TSO-DSO modelling that could be used in future real-world analysis and market design algorithms.

First, chapter 3 modelled a complete market sequence with relatively detailed FSP modelling. It also showed the application of data clustering in one-year case studies, backed by the comparison between model results and real data. It also adapted constraints to include a meshed-to-meshed topology, covering the most typical TSO-DSO voltage level division in Europe. This model allows for studies on actual flexibility usage to be implemented. It could be used for cost-benefit analyses on actual grids, for instance, in which DSOs compare LFMs against network reinforcement.

Second, chapter 4 developed a bilevel model that can be used for the testing of different regulatory mechanisms. In the context of interface flow pricing, the bilevel model developed in this thesis is a blank slate for regulatory experimentation. The cap and floor mechanism proposed in chapter 4 is an initial mechanism that can be further improved. Considering that the upper level of the bilevel problem remains a straightforward MILP, different mechanisms in the form of constraints can be evaluated, possibly leading to a better fine-tuning in terms of total system's cost and cost allocation.

6.1.4 Data management and exchange

The topic of data management and exchange is one that remained mostly outside the scope of this thesis. However, it can be said that the solutions proposed in chapter 4 contribute for the actual implementation of CSs with simpler data exchange.

It is shown in chapters 2 and 3 that the Common CS is the most economical from a flexibility procurement cost perspective. It is also shown and exemplified that decomposition techniques could be used to allow for a distributed implementation of the Common CS, overcoming the data privacy issue inherent to the centralized implementation of this CS (see Appendix B). However, the decentralised Common CS is very intensive in real-time data exchange. By proposing a regulatory alternative to interface flow pricing, this thesis suggests that second-best CSs can be implemented with minimum information exchange.

6.2 Original Contributions

The development of this thesis has yielded several original contributions to the current knowledge on TSO-DSO coordination. These are summarized below:

1. The modelling and testing of different CSs and different market design options for LFMs (i.e., OPF and PTDF-based) in one whole year analyses, plus realistic case studies for two countries. This contribution covers a gap in the literature, namely the lack of real-world studies on TSO-DSO coordination, as most of publications are focused on theoretical studies on coordination schemes and computations over synthetic test cases with limited temporal representation. This contribution is also reflected in Cossent et al. (2022), Lind et al. (2021c), and Lind et al. (2023).

2. The implementation of a meshed-to-meshed topology in the modelling of CSs. This type of modelling is necessary as an important part of TSO-DSO coordination in Europe will take place at EHV-HV substations. In addition, it was identified that most of the literature only covers meshed-to-radial topologies in synthetic case studies. This contribution is also reflected in Cossent et al. (2022) and Lind et al. (2023).

3. The introduction of the Non-Served Flexibility concept in sensitivity analysis for flexibility deployment, as well as the identification of risks and benefits of flexibility usage in realistic case studies. By modelling and simulating real-world case studies, it was possible to identify and quantify this metric not previously identified in the literature. This contribution is also reflected in Cossent et al. (2022) and Lind et al. (2023).

4. The development of a bilevel model to study interface flow pricing with an incentive-driven TSO. This model can be readily used to test regulatory mechanisms. This work is a direct contribution to the field of "TSO-DSO interface flow pricing" research. This contribution is also reflected in the *"TSO-DSO Interface Flow Pricing: A bilevel study on efficiency and cost allocation"* manuscript, submitted to the International Journal of Electrical Power & Energy Systems, currently under the peer-review process.

5. The publication of the bilevel model code in GAMS language developed in 4 under open source licence, as well as the datasets used (Lind et al., 2024b).

6. The proposal of a regulatory mechanism to the Fragmented CSs offering favourable results in terms of total system's cost and TSO-DSO cost allocation. This proposal, too, is a contribution to the interface flow pricing field. Moreover, it proposes a new field of research based on the latter, namely the use of regulatory pricing mechanisms to achieve TSO-DSO coordination. This contribution is also reflected in the *"TSO-DSO Interface Flow Pricing: A bilevel study on efficiency and cost allocation"* manuscript, submitted to the International Journal of Electrical Power & Energy Systems, currently under the peer-review process.

7. The execution of a survey with multiple stakeholders in European countries revealing drivers and barriers to the exploitation of flexibility-related activities. This survey, together with the analyses conducted and conclusions obtained, provides a practical assessment on the underlying conditions needed for TSO-DSO coordination for flexibility procurement to reach its full potential. This contribution is also published in Cossent et al. (2020b), Cossent et al. (2020c), Lind et al. (2021a), Lind et al. (2019b), and Valor et al. (2021).

8. The development of a regulatory comparison methodology and the evaluation of regulatory conditions for TSO-DSO coordination in different European countries. This methodology allows for a replicable assessment of regulatory conditions for actual TSO-DSO coordination. This contribution is also published in Cossent et al. (2020a), Cossent et al. (2022), and Lind and Chaves Ávila (2019). Indirectly, several other regulatory country assessments were conducted in the course of this thesis, including also the assessment of TSO-DSO related aspects and the formulation of recommendation to overcome potential regulatory barriers. These works are published in Cossent et al. (2020a), Cossent et al. (2017), Lind et al. (2020), Lind et al. (2021d), and Lind et al. (2018).

6.3 Publications

The thesis developments and original contributions have been presented in the following publications.

Journal papers

- L. Lind, R. Cossent, J. Chaves-Ávila, and T. Gómez San Román (2019a). "Transmission and Distribution Coordination in Power Systems with High Shares of Distributed Energy Resources Providing Balancing and Congestion Management Services". *Wiley Interdisciplinary Reviews: Energy and Environment* 8:6. ISSN: 20418396. DOI: 10.1002/wene.357

- L. Lind, R. Cossent, and P. Frías (2023). "Evaluation of TSO–DSO Coordination Schemes for Meshed-to-Meshed Configurations: Lessons Learned from a Realistic Swedish Case Study". *Sustainable Energy, Grids and Networks* 35, p. 101125. ISSN: 23524677. DOI: 10.1016/j.segan.2023.101125

- L. Lind, J. P. Chaves-Ávila, O. Valarezo, A. Sanjab, and L. Olmos (2024a). "Baseline Methods for Distributed Flexibility in Power Systems Considering Resource, Market, and Product Characteristics". *Utilities Policy* 86, p. 101688. ISSN: 0957-1787. DOI: 10.1016/j.jup.2023.101688

- C. Valor, L. Lind, R. Cossent, and C. Escudero (2021). "Understanding the Limits to Forming Policy-Driven Markets in the Electricity Sector". *Environmental Innovation and Societal Transitions* 40, pp. 645–662. ISSN: 2210-4224. DOI: 10.1016/j.eist.2021.10.022

- O. Valarezo, T. Gómez, J. P. Chaves-Avila, L. Lind, M. Correa, D. U. Ulrich Ziegler, and R. Escobar (2021). "Analysis of New Flexibility Market Models in Europe". *Energies* 14:12, p. 3521. DOI: 10.3390/en14123521

- L. Lind, R. Cossent, P. Frías (2023). *TSO-DSO Interface Flow Pricing: A bilevel study on efficiency and cost allocation*. Paper submitted to the International Journal of Electrical Power & Energy Systems, currently under the peer-review process.

Conference papers

- L. Lind, R. Cossent, and P. Frías (2019b). "New Business Models Enabled by Smart Grid Technology and Their Implications for DSOs". In: *Proc. of the 25th International Conference on Electricity Distribution (CIRED 2019)*. DOI: http://dx.doi.org/10.34890/564

- L. Lind, C. Valor, R. Cossent, V. Labajo, and C. Escudero (2021a). "New Business Models at Distribution Grids: A Stakeholder Consultation". In: *CIRED 2021 - The 26th International Conference and Exhibition on Electricity Distribution*. Vol. 2021, pp. 3140–3144. DOI: 10.1049/icp.2021.1496

- L. Lind, R. Cossent, and P. Frías (2021c). "Evaluation Framework for the Assessment of Different TSO-DSO Coordination Schemes". In: *1st IAEE Online Conference*

- G. Gürses-Tran, A. Monti, J. Vanschoenwinkel, K. Kessels, J. P. Chaves Ávila, and L. Lind (2021). "Business Use Case Development for TSO–DSO Interoperable Platforms in Large-Scale Demonstrations". In: DOI: 10.1049/oap-cired.2021.0188. (Visited on 10/23/2021)

Technical reports

- L. Lind, R. Cossent, T. Gómez, and J. P. C. Ávila (2022b). *IElectrix D4.5 - Regulatory Recommendations*. Technical report
- L. Lind, J. P. C. Ávila, A. Ivanova, J. Farré, V. Aragonés, M. Pardo, D. Davi, F. D. Martin, A. G. Martínez, J. J. P. Peña, C. Madina, M. Santos, I. Gomez-Arriola, V. Benjumeda, and M. Marroquin (2022a). *CoordiNet D3.5 - Evaluation of Preliminary Conclusion from Demo Run*. Technical report
- L. Lind, J. P. Chaves-Ávila, A. Barlier, J. M. Cruz, M. Louro, R. Prata, C. Silva, B. A. Santos, D. M. Utrilla, A. Lucas, J. Villar, G. Glória, J. Saragoça, S. M. Delgado, M. Á. S. Bodas, C. V. Silvestre, R. Pestana, R. Losseau, and S. F. de Andrés (2021b). *OneNet D9.1 - Specifications and Guidelines for Western Demos*. Technical report
- L. Lind, R. Cossent, L. Herding, M. Correa, T. Gómez, and J. P. Chaves (2021d). *IElectrix D4.4 - Current Regulation in Target Countries and Regulatory Barriers Identified for the Implementation of the Use Case*. Technical report
- L. Lind, R. Cossent, T. Gomez, P. Frías, and J. P. Chaves Ávila (2020). *InteGrid D7.2 - Regulatory Barriers in Target Countries and Recommendations to Overcome Them*. Technical report, p. 184
- L. Lind and J. P. Chaves Ávila (2019). *CoordiNet D1.1 - Market and Regulatory Analysis: Analysis of Current Market and Regulatory Framework in the Involved Areas*. Technical report
- L. Lind, R. Cossent, L. Simons, J. P. Chaves Ávila, and P. Frías (2018). *InteGrid D7.1 - Updated Comparative Analysis of Regulatory Frameworks in the Target Countries*. Technical report
- D. Trakas, L. Lind, R. Samuelsson, G. Gürses-Tran, C. Madina, I. Gomez, M. Santos, J. Vanschoenwinkel, K. Kessels, and A. Botsis (2022). *CoordiNet D6.1 - Ex-post Evaluation of the Demonstrations*. Technical report
- C. Madina, A. González-Garrido, I. Gómez-Arriola, K. Kessels, J. Vanschoenwinkel, D. Davi, E. Faure, Y. Ruwaida, N. Etherden, L. Lind, and O. Valarezo (2022). *CoordiNet D6.3 - Economic Assessment of Proposed Coordination Schemes and Products for System Services*. Technical report
- J. P. Chaves-Ávila, L. Olmos, L. Lind, A. Ivanova, J. Farré, M. Pardo, D. Davi, F. D. Martin, C. Ojeda, O. Barreiro, A. Gil, J. J. Peiró, C. Madina, M. Santos, N. Ruiz, M. Barbero, G. Leclercq, A. Debray, and V. Benjumeda (2022). *CoordiNet D3.7 - Final Spanish Demo Report Results and Analysis of the Full-scale Demonstration*. Technical report
- R. Samuelsson, M. D. Larsson, K. Kessels, J. Vanschoenwinkel, A. Sanjab, A. Delnooz, N. Neyestani, L. Lind, M. Troncia, J. P. Chavez-Ávilla, R. C. Arín, D. Trakas, D. Papadaskalopoulos, G. Gürses-Tran, M. S. Mugica, C. M. Doñabeitia, I. G. A. .-. Tecnalia, and U. Stecchi

(2022). *CoordiNet D6.7 - Roadmap towards a New Market Design Including the Implementation of Standardised Products for System Services*. Technical report

- S. Liverani, K. Glennung, S. Vogel, O. Cerny, M. Baron, J. P. C. Ávila, L. Lind, R. Cossent, R. Samuelsson, A. Sanjab, K. Kessels, D. D. Arderius, and M. Uslar (2022). *CoordiNet D7.2.3 - Common Position Paper with Related Projects in the Same Call*. Technical report

- R. Cossent, L. Lind, O. Valarezo, M. Troncia, and J. P. Chaves (2022). *CoordiNet D6.4 - Scalability and Replicability Analysis of the Market Platform and Standardized Products*. Technical report

- M. Troncia, O. Valarezo, R. Cossent, L. Lind, L. O. Camacho, and J. P. Chaves-Ávila (2021). *OneNet D2.4 - OneNet Priorities for KPIs, Scalability and Replicability in View of Harmonised EU Electricity Markets*. Technical report

- K. Drivakou, T. Bachoumis, A. Tzoumpas, C. Augusto, S. Giovanett, F. Dominguez, M. Troncia, L. Lind, F. Oliveira, S. Gandhi, J. M. Cruz, and C. D. Silva (2021). *OneNet D2.3 - Business Use Cases for the OneNet*. Technical report

- Nicolas Stevens, Keno Merckx, Pierre Crucifix, Inés Gómez, Maider Santos-Mugica, Ángel Díaz, Anibal Sanjab, Kris Kessels, Enrique Rivero, Yuting Mou, José Pablo Chaves Ávila, Leandro Lind, Luis Olmos Camacho, and Orlando Valarezo (2021). *CoordiNet D2.1 - Markets for DSO and TSO Procurement of Innovative Grid Services: Specification of the Architecture, Operation and Clearing Algorithms*. Technical report

- R. Cossent, L. Lind, L. Simons, P. Frías, C. Valor, and M. Correa (2020b). *InteGrid D7.5 - Business Models to Support the Developed Concepts*. Technical report

- R. Cossent, L. Lind, C. Valor, V. Labajo, and C. Escudero (2020c). *InteGrid D7.6 - Stakeholder Consultation*. Technical report

- R. Cossent, L. Lind, M. Correa, T. Gómez, A. R. Castanho, and M. P. Morgado (2020a). *InteGrid D8.2 - Economic and Regulatory Scalability and Replicability of the InteGrid Smart Grid Functionalities*. Technical report

- J. P. Chaves-Ávila, T. Gómez, L. Lind, M. Á. Sánchez Fornié, and L. Olmos (2020). *CoordiNet D3.1 - Report of Functionalities and Services of the Spanish Demo*. Technical report. CoordiNet Project. (Visited on 11/12/2021)

- R. Cossent, L. Lind, and L. Simons (2017). *InteGrid D1.3 - Current Market and Regulatory Incentives and Barriers*. Technical report

6.4 Future lines of research

The outcomes of this thesis have permitted the identification of new lines of research that could be interesting to explore in future works. Given the multidimensional characteristic of this thesis, findings from the different chapter could be further investigated.

- Chapter 3 proposes the evaluation of realistic case studies for entire countries. However, only selected sub-transmission grids are used, due to data limitations and the scope of the studies conducted. This could be expanded, however, utilising a complete sub-transmission representation of a country, revealing important information on the whole system. This is especially important for the computation of total costs for the TSO, considering that in Europe, most TSOs coincide with the whole transmission network of a country.

- Chapter 4 proposes an initial regulatory mechanism limiting strategic behaviour of TSOs while still maintaining incentives for economical FSP activation. This type of mechanism should be further explored. The present mechanism could be tested on realistic case studies. For instance, the type of case study used in chapter 3, considering data for one year for specific countries, could be used. This would allow for actual regulatory mechanisms to be tested, leading to proposals that could be implemented by regulators. In addition, more elaborate mechanisms could be proposed and tested. For instance, bonus-malus scheme, widely used in natural monopoly regulation, could be proposed. This type of mechanism does not only act as a hard cap and floor, but offers a linear incentive between the cap and floor, so that the incetivised SO is led to the most desirable outcome. Moreover, other approaches to the interface flow pricing should be tested, such as assuming that the TSO has the capability to compute interface flow prices and is required by regulation to do so optimally without economical incentives. Assuming that the TSO has perfect information, this could be possible. However, other effects such as the need for regulatory supervision would have to be evaluated.

- The model from chapter 4 could also be adapted to include meshed-to-meshed networks and a somewhat more detailed representation of FSPs, as well as inter-temporal constraints. This, however, is a difficult challenge considering the lower levels should remain primarily linear for the employment of the KKTs. To overcome this, other techniques for solving bilevel models could be explored. Also, depending on the voltage levels considered in the particular case studies, a DC-OPF formulation could be used for HV distribution grids (as used in chapter 3, allowing for the meshed-to-meshed setting to be simulated in the bilevel formulation.

- The analysis in chapter 4 only covered the Fragmented CS given its generality and in order to keep the analysis tractable. In future research, other CSs could be included, as well as other services, such as balancing and voltage control. The latter, for instance, could require the modelling of a reactive power market, which would pose challenges to the transmission OPF (as an AC-OPF relaxation for meshed networks is not trivial). However, the model could readily be used in case studies in which voltage problems are solved only using active power (e.g. exploiting the monotonic decreasing of voltage magnitude along feeders), an effective practice in lower voltage levels.

- The analysis in chapter 4 should also be expanded to study the interaction of the mechanisms proposed and potential strategic behaviours from the FSPs. These behaviours are also being explored in the literature, such as the "inc-dec" (an acronym for "increase-decrease") behaviour, which FSPs could use to game flexibility markets.

- Both analysis in chapters 3 and 4 should be expanded to include different market conditions observed in different countries and for different services. Mainly, the market conditions for downward bids, which can vary from country to country and service to service. These differences (e.g., having negative and positive downward prices in different markets and/or voltage levels) could unveil new dynamics for TSO-DSO coordination and incentive-driven behaviours.

- For both models in chapters 3 and 4, remains the question on the absolute differences in the terms of economic efficiency of CSs. In chapter 3, the main challenge is the inclusion of subtransmission grids (or even MV and LV distribution grids) for a whole country or at least region. This poses challenges in terms of modelling and case study assembling, but is necessary to evaluate, in absolute terms, the difference in terms of total system costs for the different CSs. In 4, results obtained for the case study proposed show a low difference from among options. This however, is also case-dependent, and further studies are necessary to calculate absolute values, especially when considering realistic case studies.

- Findings from the regulatory analysis in chapter 5 of this thesis can also be expanded to include proposals and conclusions from the modelling of previous chapters. On the one hand, the modelling of TSO-DSO coordination schemes in realistic case studies can provide actual data for the development of cost-benefit analyses for several business models. On the other hand, the compatibility of coordination incentives, such as the one proposed in chapter 4, can be verified for different countries.

- Future work could study actors who have participated in the stakeholder consultation presented in chapter 5 to examine how the anticipated barriers have been removed or navigated.

- The regulatory assessment of chapter 5 could be expanded to other countries but could also be repeated on the countries analysed in this study to understand how, when and if barriers are being removed. This temporal dimension, often neglected in regulatory studies, has the potential to reveal the dynamics behind the adoptions of regulation for different topics.

Appendices

A Baselining Flexibility Services

Typically, flexibility products are traded in the form of capacity, energy or both. The former can be defined as a band of available flexibility with a fixed duration to be (partially or fully) activated or not by the buyer (e.g., the TSO the DSO) under certain conditions. Thus, during the service provision, the FSP is available for its flexibility to be activated in the amount defined in the product, and this availability is usually remunerated in €/MW (which could be complemented by remuneration for activation). An energy product has a pre-defined activation, meaning that both buyer and seller know when the activation starts and ends and the quantity of flexibility to be delivered by the time the product is traded. This type of product is usually remunerated in €/MWh.

Among the most well-established markets in Europe are the balancing markets. These markets trade both capacity and energy products. According to ENTSO-E (2021b), capacity products are procured in a market-only fashion by TSOs for Frequency Contingent Reserves (FCR) in 14 MSs, aFRR in 16 MSs and mFRR in 17 MSs. Energy products, too, are procured for FCR in 3 MSs, aFRR in 10 MSs and mFRR in 19 MSs. While the provision of capacity products may take place differently depending on the activation mode (e.g., activation when needed or through mandatory participation in energy markets), energy products generally follow a more standardised activation process. Typically, the verification of the product delivery in balancing markets takes place by comparing the flexibility provided (metered data) with the generation or consumption schedule of the market agent. This schedule is determined in the wholesale energy markets. The agent is, therefore, a BRP over that schedule. In the absence of such a schedule, alternative verification methods would be required to estimate the counterfactual position (i.e., injection or consumption levels) of an FSP (i.e., individual or collection of flexibility resources) had they not activated their flexibility, which would allow estimating the value of flexibility delivered. In other words, the delivered flexibility would be the difference between the meter outcome at the time of activation and the estimated counterfactual position. This counterfactual position, known as the baseline, is critical for the participation of DERs in flexibility provision.

Indeed, the participation of DERs in flexibility markets is being proposed, tested and implemented as part of the decarbonisation and decentralisation strategies in power systems. EU regulations already mandate the possibility of demand-side response participation in balancing markets and are currently being implemented in many countries (smartEn, 2018). The provision of distributed flexibility to DSOs is also at the centre of the debate. Current EU regulation also calls for using local flexibility by DSOs to help manage the grid, possibly deferring or avoiding network reinforcements (European Commission, 2019a). Therefore, many initiatives have focused on demonstrating and implementing large-scale local flexibility markets (Ruwaida et al., 2023; Valarezo et al., 2021). However, verifying energy product delivery is a key challenge for distributed flexibility provision. A schedule exists in traditional balancing and wholesale energy markets, serving as the delivery verification baseline. For DERs, this schedule does not individually exist. When DERs are active consumers, a schedule exists in an aggregated form, which the retailer is responsible for balancing. However, no individual schedule exists for the specific DERs participating in flexibility markets. Therefore, a key challenge for the successful deployment of distributed flexibility is to unambiguously define the level against which to measure the amount of flexibility (product) delivered, or in other words, a baseline (Schittekatte et al., 2021). With the publication of the proposal for the Electricity Market Reform in Europe, the development of baseline methods becomes necessary, now expressed in the proposal (European Commission, 2023a). The proposal mentions that the baseline should reflect "the expected electricity consumption without the activation of the peak shaving product" in the specific case of the new flexibility product to be procured by the TSO.

Baselining DERs is not a new problem. With the first demand response programs came the need to define a baseline method. Several were developed and implemented, primarily relying on statistical information on past consumption (AIEC, 2009; EnerNOC, 2009). Most of these methods, however, were tailored-made for demand response programs in which the only type of service provider was the active consumer, and the only product was upward flexibility provisions (e.g., reduction of consumption). Therefore, the suitability of these methods has been chiefly analysed from the perspective of demand response (Antunes et al., 2013; Jazaeri et al., 2016; Mohajeryami et al., 2017a; Wijaya et al., 2014). Adaptations to the consumer's baseline have been proposed and analysed for specific groups of DERs. For example, in Fonteijn et al. (2021), a variation is proposed for PV units, while in Arunaun and Pora (2018), a method is explicitly proposed for industrial loads.

The participation of distributed flexibility in the present and future flexibility markets is notably more complex. The many types of DERs include demand-side resources, DG, storage systems, and aggregated DERs in different forms (different resources behind the meter, energy communities, independent aggregators). Markets and products are complex and upward and downward flexibility may be traded and activated. Procurement may occur from minutes before delivery (e.g., in the MARI cross-border platform) to months ahead for some capacity products in national balancing markets (ENTSO-E, 2021b; ENTSO-E, 2023). Such differences pose a fundamental question to the baselining of DERs: Are the available methods suitable for the efficient participation of DERs in current and future flexibility markets?

In Lind et al. (2024a), an analysis is made of the existing baseline methods proposed by academia and practitioners through an evaluation framework considering the characteristics of modern distributed flexibility provision. Firstly, baseline methods are characterised by data needs for their application, who is responsible for the baseline calculation, if close-to-real-time adjustments are allowed, and if the baseline is dynamic or static. These features serve as input for the subsequent analysis of baselines. Secondly, the baseline methods are evaluated according to their accuracy, simplicity and integrity in various modern flexibility provision use cases, including different types of DER, aggregation, different directions of activation and market timing. As a result, this study proposes a novel set of guidelines for selecting a baseline for DER participation in flexibility markets. This guideline provides a reference for selecting suitable baseline methods for flexibility trading in future flexibility markets.

A.1 Baseline Methods

Different baseline methods have been progressively proposed in the academic literature and by practitioners. Valentini et al. (2022) show that most methods currently used in international practice and European research projects rely on historical data, i.e., using metered data at the same time as the activation time (i.e., the time at which the flexibility is supposedly delivered) but from previous days that share similar criteria with the activation day (such criteria can be simply the type of day, e.g., weekday vs weekend). A common type of baseline method based on historical data is what is known as the XofY method (and its variations) (Arunaun and Pora, 2018; Mohajeryami et al., 2017a; Mohajeryami et al., 2017b; Ramos, 2019; Rossetto, 2018; Wang and Tang, 2022). The HighXofY, for instance, considers the average profile of the X days with the highest consumption within the set of Y-eligible previous days (e.g., weekdays if activation takes place on a weekday). Another method involving only the use of historical metered data is the rolling average of the previous X days of the same type (e.g., weekdays), potentially increasingly weighting the most recent days in order to capture the most current determinants for consumption, e.g., temperature and weather conditions (Holmberg et al., 2013; Miriam L. Goldberg and G. Kennedy Agnew, 2013; Tufts and Breidenbaugh, 2010). In addition, a comparable day to the activation day was proposed as a baseline for demand response. In this method, the flexibility provider chooses ex-post a non-activation day in the past that would reflect the conditions of the event day (EnerNOC, 2011). These methods have one characteristic in common: only metered data is required to calculate the baseline. Eventually, a Same-Day Adjustment (SDA) can be performed using additional data, such as weather-based adjustments. Another common method that relies on statistical data is the regression method. Regression models (mostly linear or polynomial) use a set of historical data to estimate a function that represents the relationship between the dependent variable (baseline consumption) and the independent variables (e.g., past consumption, season, weather, day-of-the-week) (Arunaun and Pora, 2018; Mohajeryami et al., 2017a; Vagropoulos et al., 2022).

More recently, novel methods based on neural networks and other Machine Learning (ML) techniques emerged, promising a higher accuracy for baseline estimation (Park et al., 2015). These methods are here differentiated from the regression method (which can also be classified as an ML technique) considering the extensive adoption of the latter, the heterogeneity of mathematical techniques employed for other ML algorithms and for providing a less transparent model for regression models (e.g., the hidden layers in neural networks). Examples of other ML techniques used in baseline estimation are Artificial Neural Network, Convolutional Neural Network, and Long Short-Term Memory algorithms (Campodonico Avendano et al., 2023).

A.2 Baseline Evaluation for Flexibility Market Characteristics

Typically, baseline methods are evaluated in terms of their *accuracy*, *simplicity*, and *integrity*. These criteria were first introduced by EnerNOC (2009) and later used by other authors (Arunaun and Pora, 2018; Jazaeri et al., 2016; Valentini et al., 2022). For a method to be accurate, the baseline computed should correctly estimate the level of consumption or production if the available flexibility is not activated. In addition, the method should be simple enough for stakeholders to understand, implement, and verify its outcome. Simplicity is a desired attribute from the implementation point of view to ensure that the method is transparent for both flexibility buyers and sellers. Additionally, the criterion integrity refers to the extent to which a baseline method does not allow the seller or buyer to misrepresent the flexibility delivered for their benefit. The intended misrepresentation of the flexibility delivered should be considered a case of manipulation or gaming behaviour (e.g., increasing the consumption just before flexibility delivery when this is measured using a Meter-Before-Meter-After (MBMA) baseline method).

These three criteria, however, have usually been applied to analyse and define baseline methods for simpler tailor-made demand response programs (e.g. peak shaving provided by flexible loads).

In this study, the three baseline evaluation criteria are used to evaluate the suitability of the baseline methods for the three different key flexibility market characteristics, which are: (i) baselines for different DERs, (ii) multi-DER baseline (e.g., behind the meter, aggregators), and (iii) the characteristics of flexibility services. First, the DER technology used in the flexibility provision is analysed from the baseline perspective. In this study, the assessment is done for flexible load DERs and controllable and non-controllable DG and ESSs. Second, baselines for multi-DER FSPs are analysed. These result from aggregating different technologies behind or in front of the meter. The suitability of each baseline method in this case is assessed. Finally, the baseline methods are assessed against the characteristics of the flexibility services, specifically their timing (e.g., week-ahead vs. close to real-time) and direction of activation (upward vs. downward flexibility).

Following this qualitative discussion on the fitness of the different baseline types, a decision framework is built to identify the possible baseline types for the different use cases in flexibility markets. Figure A.1 depicts a representation of the assessment framework considered in this research work. According to it, the three intrinsic baseline criteria are used to evaluate the different baseline methods in the context set by the several flexibility provision characteristics considered.

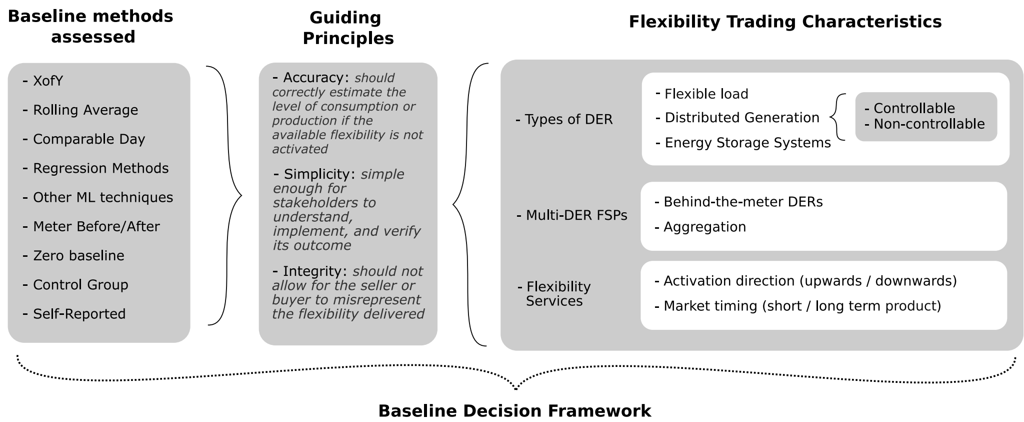

Figure A.1: Representation of assessment framework. Source: Lind et al. (2024a).

A.3 Different Baseline Methods for Different Flexibility Use Cases

The analysis in Lind et al. (2024a) assesses first the fitness of the different baseline methods (listed in Figure A.1) for different types of DER, including (i) flexible loads, (ii) controllable DG (e.g. backup generation, Combined Heat and Power (CHP)), (iii) non-controllable DG (e.g. solar PV, wind), and (iv) ESS (e.g. stationary battery, Vehicle-to-Grid (V2G) EV).

The analysis concluded that the fitness of methods in terms of the three guiding criteria (i.e. accuracy, simplicity and integrity) varies greatly. For example, while past-days profile averaging methods such XofY or Rolling Average may be a better fit for flexibility loads, they may not be accurate for non-controllable DG or may suffer from integrity risk for ESSs.

An analysis is also made for aggregation of baselines. More broadly, the analysis considers Multi-DER FSPs, meaning both individual FSPs that have multiple types of DER behind the meter (e.g. residential consumer with flexible loads, EV and a PV installation), and aggregators that aggregate multiple FSPs.

While some techniques for baseline decoupling do exist (e.g., Li et al. (2019) and Xuan et al. (2020)), the simplicity of the methods is greatly reduced. Separate baseline methods can be used per type of technology or type of DER within an aggregated portfolio. In other words, specific baseline methods can be applied to the different DER types according to what best fits each. However, additional submetering data would be necessary for multiple DER types per metering point, such as for a consumer with a PV installation and an EV charging station.

In Europe, submetering is possible for TSOs and DSOs to gain observability and settle flexibility provision. The Draft of the Electricity Market Reform from March 2023 includes the possibility of system operators using data from "dedicated metering devices" for this purpose (European Commission, 2023a). On the one hand, this approach would increase the accuracy of the portfolio's baseline computed but, on the other, decrease its simplicity. Also, submetering devices and data would have to be certified.

As an alternative to using submetering data to decouple the determination of the baseline for each of several technologies, FSPs could be grouped into clusters, and specific baseline methods could be applied to each of those according to these clusters' characteristics (Li et al., 2017; Schwarz et al., 2020; Zhang et al., 2016). A cluster could be defined according to the types of DERs it includes. For example, residential consumers would form one cluster, like those with PV or EV. The advantage of this approach is that no additional data is required apart from the existing metering data. Its main disadvantage is that the level of accuracy in baseline determination may be impacted negatively by the consideration of portfolios of assets of different types (especially in the absence of appropriate metering). Finally, another alternative is to use the aggregated profile of a control group of end-users as the baseline for the aggregated FSP (Wang et al., 2018). For both types of solutions, the size of the aggregator's portfolio might impact the accuracy achieved in the baseline computation. A higher accuracy can be expected for large portfolios, considering the law of large numbers. Also, regarding the size of the aggregated portfolio and its geographical footprint, this footprint must be limited by the borders of the flexibility market area, both for granting permission to participate in the market and for baseline definition.

Product direction and market timing may also play a role in the baseline method choice. With regard to the former, most baseline methodologies can, in principle, be suitable for both upward and downward products concomitantly (e.g., redispatch type of markets). The baseline design, however, may impact the performance of different products. Some baseline methods are notably biased in a particular direction to incentivise flexibility provision. The HighXofY method is known for having an upward bias as an incentive for upward flexibility provision Wijaya et al. (2014). For downward flexibility, however, this would act as a disincentive, as the up bias would reduce the amount of flexibility deemed to be provided and remunerated by the buyer. Variations such as the MidXofY or the LowXofY could be more appropriate.

With regard to market timing, the baseline method choice should consider if appropriate time for baseline calculation (if needed) exists. For example, if the activation decision is taken for close to the activation (e.g. capacity products or short Gate-Closure Time (GCT) to activation, such as the MARI platform[1]). In these cases, methods with no previous calculations could be more appropriate such as the MBMA, as the short notice also helps preventing gaming. If the GCT and activation decision takes place long before product delivery, adjustments and supervision could help prevent gaming and improve accuracy.

Moreover, the size of the FSP can also be considered when selecting a baseline methodology. Industrial loads or utility-size DG and ESS can typically perform more complex energy management than residential loads. In this context, the relative importance of simplicity may be reduced in favour of accuracy. In this case, the parties procuring flexibility or regulatory authorities can also check integrity more closely. In this context, the self-reported baseline method becomes a more appropriate option for these types of FSP.

A.4 A Decision Framework for Baseline Method Selection

Considering the assessment above within the proposed methodology, a decision framework for baseline selection is proposed and presented in Figure A.2.

The decision framework presented in A.2 provides guidelines that policymakers and regulators could use in deciding the specific baseline methods for the different flexibility use cases (e.g., type of FSP, DER, and multi-DER presence). However, other considerations might also be relevant from a policy perspective.

Firstly, regulators might want to opt for a reduced set of baseline methods for simplification, possibly at the expense of accuracy. A good example is the baseline tool developed and tested in the UK, proposed by the joint association of transmission and distribution network operators. In this tool, five different methods can be chosen for three types of DERs: demand, generation and "storage/mixed" (Energy Networks Association, 2021). The experience from six countries in the EU Horizon 2020 project OneNet also showed that a fallback option might be necessary in case the FSP chooses a self-reported baseline but fails to provide one (Reif et al., 2023).

Secondly, regulators might consider the effects of baseline rules rigidity on the development of distributed flexibility services. The EU Horizon 2020 project CoordiNet recommends, for instance, that baseline methods should focus on the incentives for customers to participate in

[1] MARI cross-border platform for the exchange of mFRR bids between TSOs. In this platform, 15 minutes separate GCT to the point the FSP should have ramped up to the full provision of flexibility (ENTSO-E, 2017).

flexibility provision during the early stages instead of defining strict penalties for non-delivery of procured flexibility (Samuelsson et al., 2022).

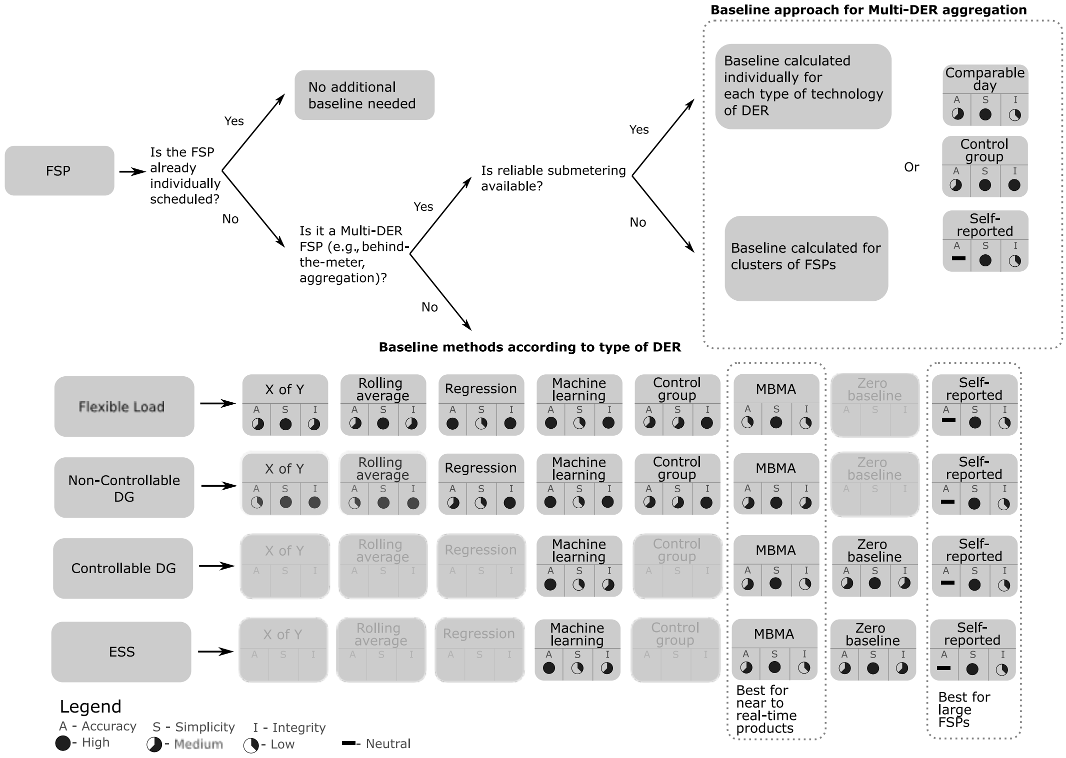

Figure A.2: Baseline decision framework according to FSP, DER, and multi-DER presence type. Source: Lind et al. (2024a).

B Benders' decomposition applied to TSO-DSO Coordination

Decomposition techniques can be used to split an optimisation problem in two or more problems and therefore make use of parallel computing in order to achieve a faster execution of large problems. Nevertheless, in the context of TSO-DSO Coordination, decomposition techniques can be used to implement the Common CS in a distributed way. More than achieving computational efficiency, the use of a decomposition technique can contribute to preserving data privacy from TSOs and DSOs and to reduce the exchange of information between the two SOs. In this Appendix, an example is given using Benders' decomposition technique.

Let us consider the following implementation of the Common CS (B.1), based on DC OPF plus LinDistFlow formulation presented in Chapter 4. For being a Common CS, no interface price formulation is considered. The objective function (B.1a) only considers the cost of flexibility activated upward and downward, separated by SO for presentation purposes only. Constraints are similar to the ones presented in Chapter 4, and are here separated in blocks for presentation too. Equations (B.1b)-(B.1m) are TSO-exclusive, while (B.1n)-(B.1ad) are DSO-exclusive. While at some instances redundant (e.g. bounds on variables such as flexibility activated, power flow over lines, etc), this separation serves the purpose to clearly split the formulation into constraints that would require only data belonging to one or another SO. Finally, (B.1ae) is formulated. This constraint couples the TSO-DSO power flow, offering a single complicating variable $ie_{i\in Front^{TSO}}$ and the dual variable $\lambda^{ie\_TSO}_{i\in Front^{TSO}}$ to be used by the Benders algorithm.

Other decomposition techniques could be employed in which different decomposition formulations are used. The Dantzig-Wolfe or ADMM algorithms, for instance, would use a complicating constraint, instead of complicating variable (Antonio J. Conejo et al., 2006). However, considering that the objective of this Appendix is to illustrate the applicability of decomposition algorithms and not to compare them, only the Benders' algorithm is shown.

$$\begin{aligned} \min \sum_{i,s\in S^D,k} \left[\left(Bid_k^{up} \cdot p_k^{up}\right) + \left(Bid_k^{dw} \cdot p_k^{dw}\right)\right] \\ + \sum_{i,s\in S^T,k} \left[\left(Bid_k^{up} \cdot p_k^{up}\right) + \left(Bid_k^{dw} \cdot p_k^{dw}\right)\right] \end{aligned} \tag{B.1a}$$

s.t.

(1. TSO Constraints Block)

$$DispatchDA_i + \sum_{k \in IF} p_k^{up} - \sum_{k \in IF} p_k^{dw} - \sum_{j \in I^{TSO}} f_{i,j}^p + \sum_{j \in I^{TSO}} f_{j,i}^p \\ -ie_{i \in Front^{TSO}} - D_i = 0 \quad \forall i \in I^{TSO} \tag{B.1b}$$

$$ie_i = \sum_{j \in I^{SUBS}} f_{i,j}^p \quad \forall i \in Front^{TSO} \tag{B.1c}$$

$$\theta_i = 0 \quad \forall i \in SLACK^{TSO} \tag{B.1d}$$

$$f_{i,j} - SB \cdot \frac{\theta_i - \theta_j}{X_{i,j}} = 0 \quad \forall (i \in I^{TSO}, j) \in L \tag{B.1e}$$

$$p_k^{up} - P_k^+ \leq 0 \quad \forall k \in K^{TSO} \tag{B.1f}$$

$$-p_k^{up} \leq 0 \quad \forall k \in K^{TSO} \tag{B.1g}$$

$$p_k^{dw} - P_k^- \leq 0 \quad \forall k \in K^{TSO} \tag{B.1h}$$

$$-p_k^{dw} \leq 0 \quad \forall k \in K^{TSO} \tag{B.1i}$$

$$f_{i,j}^p - F_{i,j}^{p,+} \leq 0 \quad \forall (i,j) \in L \wedge i \in I^{TSO} \tag{B.1j}$$

$$F_{i,j}^{p,-} - f_{i,j}^p \leq 0 \quad \forall (i,j) \in L \wedge i \in I^{TSO} \tag{B.1k}$$

$$\theta_i - \theta^+ \leq 0 \quad \forall i \in I^{TSO+} \tag{B.1l}$$

$$-\theta^+ - \theta_i \leq 0 \quad \forall i \in I^{TSO+} \tag{B.1m}$$

(2. DSO Constraints Block)

$$DispatchDA_i + \sum_{k \in IF} p_k^{up} - \sum_{k \in IF} p_k^{dw} - \sum_{j \in I^{DSO}} f_{i,j}^p + \sum_{j \in I^{DSO}} f_{j,i}^p - ie_{i \in Front^{DSO}} \\ -D_i = 0 \quad \forall i \in I^{DSO} \tag{B.1n}$$

$$ie_i = \sum_{j \in I^{SUBS}} f^p_{i,j} \quad \forall i \in Front^{DSO} \tag{B.1o}$$

$$w_{i \in SLACK^s} - 1 = 0 \quad \forall (s \in S^{DSO}) \tag{B.1p}$$

$$\begin{gathered} + \sum_{k \in IF} q_k - \sum_j f^q_{i,j} + \sum_j f^q_{j,i} - DQ_i = 0 \\ \forall (i \in IS) \wedge (i \notin I^{SUBS}), (s \in S^D) \end{gathered} \tag{B.1q}$$

$$f^q_{i,j \in I^{SUBS}} - slackQ_{i,j} = 0 \quad \forall (i,j) \in L, (i \in IS) \wedge (s \in S^D) \tag{B.1r}$$

$$w_i - w_j - 2 \cdot (R_{i,j} \cdot f^p_{i,j} + X_{i,j} \cdot f^q_{i,j}) = 0 \quad \forall (i,j) \in L, (i \in IS), (s \in S^D) \tag{B.1s}$$

$$q_k - PFactor * (p^{up}_k - p^{dw}_k) = 0 \quad \forall k \in K^{DSO} \tag{B.1t}$$

$$p^{up}_k - P^+_k \leq 0 \quad \forall k \in K^{DSO} \tag{B.1u}$$

$$-p^{up}_k \leq 0 \quad \forall k \in K^{DSO} \tag{B.1v}$$

$$p^{dw}_k - P^-_k \leq 0 \quad \forall k \in K^{DSO} \tag{B.1w}$$

$$-p^{dw}_k \leq 0 \quad \forall k \in K^{DSO} \tag{B.1x}$$

$$f^p_{i,j} - F^{p,+}_{i,j} \leq 0 \quad \forall (i,j) \in L \wedge i \in I^{DSO} \tag{B.1y}$$

$$F^{p,-}_{i,j} - f^p_{i,j} \leq 0 \quad \forall (i,j) \in L \wedge i \in I^{DSO} \tag{B.1z}$$

$$f^q_{i,j} - F^{q,+}_{i,j} \leq 0 \quad \forall (i,j) \in L \tag{B.1aa}$$

$$F^{q,-}_{i,j} - f^q_{i,j} \leq 0 \quad \forall (i,j) \in L \tag{B.1ab}$$

$$w_i - (V^+)^2 \leq 0 \quad \forall i \in I^{DSO+} \tag{B.1ac}$$

$$(V^-)^2 - w_i \leq 0 \quad \forall i \in I^{DSO+} \tag{B.1ad}$$

(Coupling power flow constraint)

$$ie_i = - \sum_{j \in Front^{DSO} \wedge Intercon(i,j)} ie_j \quad : \quad \pi^{ie\_TSO}_{i \in Front^{TSO}} \quad \forall i \in Front^{TSO} \tag{B.1ae}$$

The Benders algorithm consists of splitting an optimisation problem into a Master problem and one or more Subproblems. In the case of the Common CS presented above, the splitting is obvious: A Master problem with TSO constraints and a Subproblem with DSO constraints. Therefore, the Master and Subproblem are formulated in (B.2) and (B.3), respectively. On the master problem, the objective function (B.2a) is modified to include only FSPs connected at the transmission. It also includes the auxiliary variable $\theta^{BENDERS}$. Equation (B.2c) introduces the Bender cuts (Antonio J. Conejo et al., 2006; Pereira and Pinto, 1991). The full Benders algorithm and the setting of the variables and parameters in (B.2c) are discussed below.

The Subproblem (B.3) includes the DSO constraints block from the Common CS (i.e. (B.1n)-(B.1ad)) plus the constraint containing the complicating variable (B.1ad).

Master Problem:

$$\min \sum_{i,s \in S^T,k} \left[\left(Bid^{up}_k \cdot p^{up}_k \right) + \left(Bid^{dw}_k \cdot p^{dw}_k \right) \right] + \theta^{BENDERS} \quad (= Z^{Master}) \tag{B.2a}$$

s.t.

$$\text{(B.1b)} - \text{(B.1m)}, \tag{B.2b}$$

$$\Delta_e \cdot \theta^{BENDERS} \geq Z^{Sub}_e + \sum_{i \in Front^{TSO}} \pi^{ie\_TSO}_{i \in Front^{TSO}} \cdot \left(IE^{ie\_TSO}_{e,i \in Front^{TSO}} - ie_{i \in Front^{TSO}} \right) \quad \forall e \in E \tag{B.2c}$$

Subproblem:

$$\min \sum_{i,s \in S^D,k} \left[\left(Bid^{up}_k \cdot p^{up}_k \right) + \left(Bid^{dw}_k \cdot p^{dw}_k \right) \right] \quad (= Z^{Subs}) \tag{B.3a}$$

s.t.

$$\text{(B.1n)} - \text{(B.1ae)} \tag{B.3b}$$

The Benders algorithm work by iteratively discovering the total cost function (i.e. (B.1b)) with respect to the complicating variable (i.e. $ie_{i \in Front^{TSO}}$). For this, first the algorithm is initialized by fixing the Masters problem's parameters Δ_e, Z^{Sub}_e, $IE^{ie\_TSO}_{e,i \in Front^{TSO}}$, and $\pi^{ie\_TSO}_{i \in Front^{TSO}}$ to an initialisation value (e.g. zero) and solving the Master problem. After that, the complicating variable $ie_{i \in Front^{TSO}}$ is fixed and passed on to the Subproblem as a parameter. In other words, the TSO sends a "proposal" for an interface power flow to the DSO. The Subproblem is then executed with this proposal and the dual variable $\pi^{ie\_TSO}_{i \in Front^{TSO}}$ is computed. The result for this dual variable along with the objective function's value Z^{Subs} are used to determine the upper and lower bounds for that iteration e, meaning the maximum and lower values for the whole problem (Master + Subproblem) estimated in each iteration. The upper and lower bounds for the Benders algorithm are calculated as shown in (B.4). In case the Subproblem is infeasible, the Master problem is penalized by the setting of $\Delta_e = 0$. Otherwise it is set to 1.

$$\underline{Z}_e = Z_e^{Master*} \tag{B.4a}$$

$$\bar{Z}_e = \min\{\bar{Z}^*_{e-1}; Z_e^{Master*} - \theta_e^{BENDERS*} + Z_e^{Sub*}\} \tag{B.4b}$$

The pseudo-code of the Benders' algorithm used is presented in Algorithm 1. The *while* block is executed until the upper and lower bounds converge within the predetermined error (here set as $\epsilon = 10^{-6}$). A high-level illustration of the information exchanged during the Benders' execution is provided in Figure B.1.

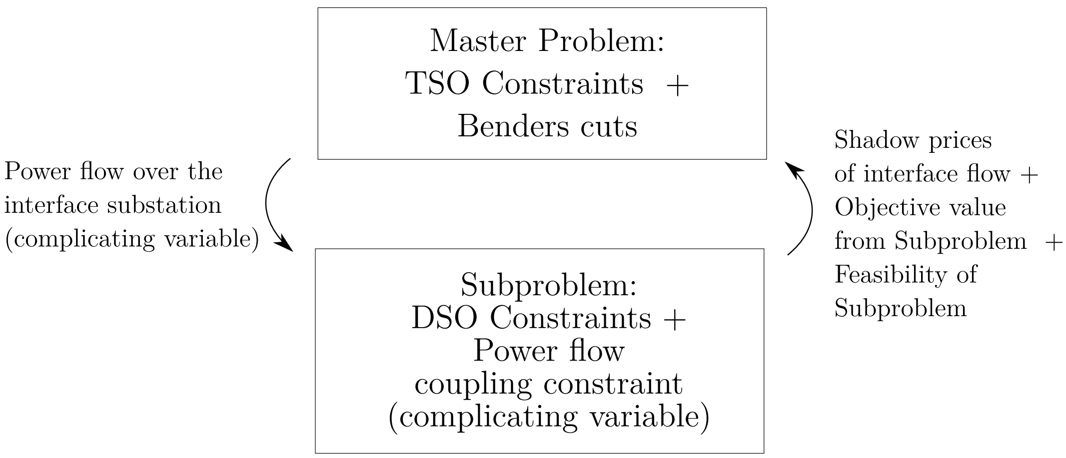

Figure B.1: Overview of the information exchanged during the Benders execution.

In order to verify its applicability, the Benders' algorithm above is tested on three case studies presented in 4, namely, the (i) Stylised Case Study, the (ii) 102-Node without TSO congestions, and (iii) the 102-Node with TSO congestions. The three case studies are executed only at their baseline form, i.e. no sensitivities applied. The data for these case studies is the one presented in D.1 and D.2.

B.1 Benders' decomposition results

Table B.1, B.2, B.3 present the results for the three cases studies. Convergence is achieved in all three. The simplest Stylised Case Study reaches convergence in six iterations, while the larger 102-Node case study takes 23 and 21 iterations to reach convergence when no TSO congestions occur and when they do, respectively. In the case of the Stylised Case Study, considering that only one

Algorithm 1 Benders' Decomposition - Decentralized Common CS

Initialise:
$\theta_{e=1}^{BENDERS} = 0$
$Z_{e=1}^{Sub} = 0$
$\Delta_{e=1} = 0$
$\pi_{i \in Front^{TSO}}^{ie\_TSO} = 0$
$IE_{e=1, i \in Front^{TSO}}^{ie\_TSO} = 0$
while $|1 - \frac{\underline{Z}_e}{\bar{Z}_e}| > \epsilon$ **do**
  Solve: (B.2)
  $IE_{e, i \in Front^{TSO}}^{ie\_TSO} = ie^*_{i \in Front^{TSO}}$
  $Ie_{i \in Front^{TSO}} = ie^*_{i \in Front^{TSO}}$
  Solve: (B.3)
  if (B.3) is infeasible **then**
    $\Delta_e = 0$
  else
    $\underline{Z}_e = Z_e^{Master*}$
    $\bar{Z}_e = \min\{\bar{Z}^*_{e-1}; Z_e^{Master*} - \theta_e^{BENDERS*} + Z_e^{Sub*}\}$
    $\Delta_e = 1$
  end if
end while

TSO-DSO interface, the values of $\pi_{i\ FrontTSO}$ and $iei\ FrontTSO$ are also presented. They show the information that is effectively exchanged during the algorithm execution, together with the Subproblem objective value Z^{Sub}. They reveal the "proposals" exchanged by SOs. Ultimately the power flow at the substation is set at 8 MW, and the dual π_{T2} reaches 10 €/MWh, which is also a valid interface price to reach the optimal total cost in the Fragemented CS (see Figure 4.3). It is worth mentioning that on the Common CS, cost allocation is not embedded to the market design, and a cost settlement among SOs would be necessary ex-post. For this reason, an interface shadow price of 10 €/MWh is enough for the algorithm to reach convergence, as any value between 10 and 30 €/MWh would be for this small case study.

Figures B.2 to B.4 illustrate the convergence for the three case studies.

Table B.1: Results for Benders: Stylised Case Study.

e	$\bar{Z}$	$\underline{Z}$	$\theta^{BEN.}$	Δ_e	Z^{Master}	Z^{Sub}	F.M.*	F.S.*	π_{T2}	ie_{T2}
1	$+\infty$	$-\infty$			11,164.73	196.71	1	4	1.00	10.00
2	15,131.37	14,811.37		1	14,811.37	320.00	1	1	30.00	10.00
3	15,131.37	14,811.37	-11,980.00		10,432.20	405.00	1	4	-1.00	5.00
4	15,131.37	15,074.07	170.00	1	15,074.07	300.00	1	1	-60.00	5.00
5	15,121.73	15,090.62	213.33	1	15,090.62	244.44	1	1	10.00	6.44
6	15,108.45	15,108.45	260.00	1	15,108.45	260.00	1	1	10.00	8.00

*Feasibility Master, Feasibility Subproblem: 1 = Feasible; 4 = Infeasible.

Table B.2: Results for Benders: 102-Bus Case Study without TSO congestions.

e	$\bar{Z}$	$\underline{Z}$	$\theta^{BEN.}$	Δ_e	Z^{Master}	Z^{Sub}	F.Master*	F.Sub*
1	$+\infty$	$-\infty$	0.00		0.00	0.50	1	4
2	440.40	$-\infty$	0.00	1	0.00	440.40	1	1
3	440.40	$-\infty$	-1,235.16		-295.55	20.24	1	4
4	440.40	$-\infty$	-594.60		-80.10	12.60	1	4
5	440.40	$-\infty$	-524.80		-10.30	9.00	1	4
6	440.40	$-\infty$	-467.24		47.26	5.12	1	4
7	440.40	57.50	-457.00	1	57.50	3,297.00	1	1
8	440.40	57.50	-101.36		149.75	5.20	1	4
9	440.40	206.89	-61.13	1	206.89	1,665.68	1	1
10	440.40	206.89	55.42		288.32	2.09	1	4
11	440.40	292.23	87.42	1	292.23	1,358.22	1	1
12	440.40	342.03	204.27	1	342.03	817.36	1	1
13	440.40	363.03	277.00	1	363.03	609.30	1	1
14	440.40	394.06	299.84	1	394.06	606.03	1	1
15	440.40	399.51	333.10	1	399.51	581.88	1	1
16	440.40	403.31	365.80	1	403.31	578.48	1	1
17	440.40	408.28	360.28	1	408.28	415.22	1	1
18	440.40	411.46	379.14	1	411.46	466.34	1	1
19	440.40	414.01	378.80	1	414.01	418.60	1	1
20	440.40	415.42	378.78	1	415.42	414.35	1	1
21	416.93	415.44	378.84	1	415.44	380.33	1	1
22	416.57	415.58	379.34	1	415.58	380.34	1	1
23	416.25	416.25	379.50	1	416.25	379.50	1	1

*Feasibility: 1 = Feasible; 4 = Infeasible.

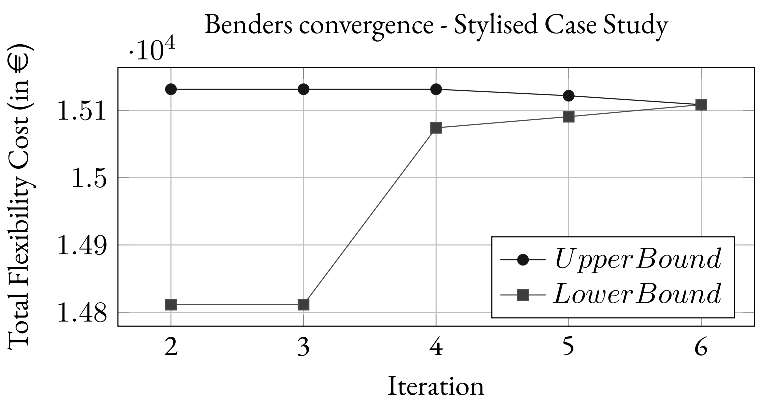

Figure B.2: Convergence of the Benders decomposition - Stylised Case Study

Table B.3: Results for Benders: 102-Bus Case Study with TSO congestions.

e	$\bar{Z}$	$\underline{Z}$	$\theta^{BEN.}$	Δ_e	Z^{Master}	Z^{Sub}	F.Master*	F.Sub*
1	$+\infty$	$-\infty$	0.00		129.28	2.26	1	4
2	$+\infty$	$-\infty$	0.00		166.42	1.51	1	4
3	1,125.68	219.88	0.00	1	219.88	905.80	1	1
4	1,125.68	219.88	-1,246.80		-122.59	15.90	1	4
5	1,125.68	219.88	-690.60		132.30	8.70	1	4
6	1,125.68	219.88	-647.63		239.98	6.09	1	4
7	1,125.68	219.88	-620.25		240.59	2.85	1	4
8	1,125.68	241.16	-594.60	1	241.16	2,841.80	1	1
9	1,125.68	241.16	-258.19		440.71	0.50	1	4
10	1,125.68	441.21	-232.79	1	441.21	1,253.21	1	1
11	1,125.68	535.98	17.33	1	535.98	761.70	1	1
12	945.61	661.35	201.90	1	661.35	486.16	1	1
13	945.61	785.79	329.47	1	785.79	959.91	1	1
14	945.61	825.44	301.11	1	825.44	487.54	1	1
15	945.61	836.45	416.09	1	836.45	636.61	1	1
16	945.61	855.47	408.65	1	855.47	557.24	1	1
17	885.26	856.39	374.14	1	856.39	403.01	1	1
18	885.26	873.78	389.72	1	873.78	423.20	1	1
19	885.26	873.83	378.94	1	873.83	406.53	1	1
20	885.26	876.17	387.41	1	876.17	411.42	1	1
21	876.65	876.65	379.50	1	876.65	379.50	1	1

*Feasibility: 1 = Feasible; 4 = Infeasible.

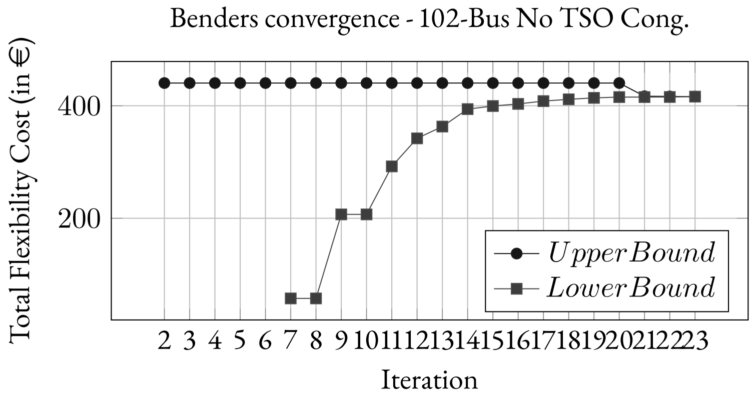

Figure B.3: Convergence of the Benders decomposition - 102-Bus No TSO Cong.

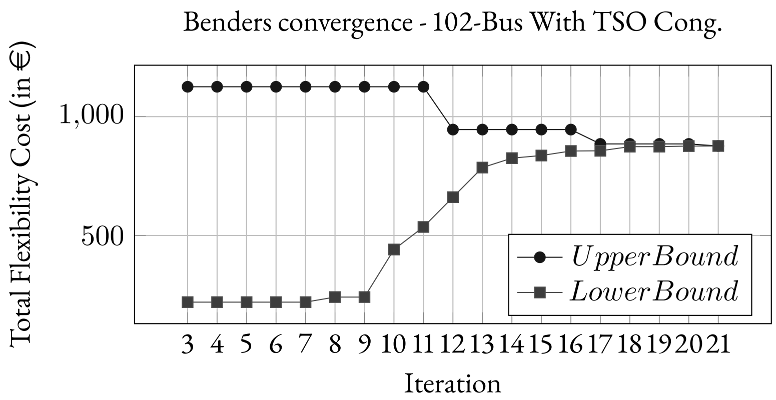

Figure B.4: Convergence of the Benders decomposition - 102-Bus With TSO Cong.

These results illustrate that the Benders decomposition can be a valid technique to allow for a Common CS to be implemented in the decentralized manner, in which each SO optimises their own grids and only exchange a minimal amount of information, none of which are, in principle, private (i.e. no grid or FSP data is exchanged), as illustrated in Figure B.1. However, the implementation of this decentralized Common CS present the drawbacks discussed in Chapters 2 and 4:

- This is still a single marketplace, and therefore, market timings have to be synchronised.
- Data has to be exchanged in real-time. ICT infrastructure becomes a key element for the implementation of this CS.
- Cost allocation is not embedded to this market design. Additional procedures are necessary to allocate costs among TSO and DSOs.

C Linearisations of the Bilevel Problem

C.1 Linearisation of the Upper Level's Objective Function

According to the Strong Duality Theorem, if x is an optimal solution to the primal problem and λ is an optimal of the dual problem, then $c^T x = \lambda^T b$. Therefore, a possible linearisation technique for the $(p_k^{up} - p_k^{dw}) \cdot intprice_s$ is to verify if a linear term exists in the equality between the primal objective function of (4.1) and its dual counterpart. Therefore,

$$
\begin{aligned}
&\sum_{s\in S^D, k\in K^{DSO}} \Big[\big(Bid_k^{up} \cdot p_k^{up}\big) + \Big(Bid_k^{dw} \cdot p_k^{dw}\Big)\Big] + \sum_{s\in S^D, k\in K^{DSO}} (p_k^{up} - p_k^{dw}) \cdot IntPrice_s \\
&= \\
&+ \sum_{i\in I^{DSO}, s\in S^D} DispatchDA_i \cdot \lambda_{i,s}^{D1} - \sum_{i\in I^{DSO}, s\in S^D} D_i^p \cdot \lambda_{i,s}^{D1} \\
&+ \sum_{i\in I^{DSO}, j\in I^{SUBS}, s\in S^D} DaDSO_s \cdot \lambda_{i,j,s}^{D2} - \sum_{i\in SLACK^s, s\in S^D} \lambda_{i,s}^{D3} \\
&- \sum_{i\in I^{DSO}, s\in S^D} D_i^q \cdot \lambda_{i,s}^{D4} \\
&- \sum_{k\in K^{DSO}} P_k^+ \cdot \bar{\mu}_k^{up} - \sum_{k\in K^{DSO}} P_k^- \cdot \bar{\mu}_k^{dw} - \sum_{i\in I^{DSO}, j} F_{i,j}^{p,+} \cdot \bar{\mu}_{i,j}^p + \sum_{i\in I^{DSO}, j} F_{i,j}^{p,-} \cdot \underline{\mu}_{i,j}^p \\
&- \sum_{i\in I^{DSO}, j} F_{i,j}^{q,+} \cdot \bar{\mu}_{i,j}^q + \sum_{i\in I^{DSO}, j} F_{i,j}^{q,-} \cdot \underline{\mu}_{i,j}^q - \sum_{i\in I^{DSO+}} (V^+)^2 \cdot \bar{\mu}_i^V + \sum_{i\in I^{DSO+}} (V^+)^2 \cdot \underline{\mu}_i^V
\end{aligned}
\tag{C.1}
$$

resulting in the following linear objective function for the upper level:

$$\begin{aligned} \min \sum_{s \in S^T, k \in K^{TSO}} (Bid_k^{up} \cdot p_k^{up}) + (Bid_k^{dw} \cdot p_k^{dw}) + \sum_{s \in S^D, k \in K^D} (p_k^{up} - p_k^{dw}) \\ - \sum_{i \in I^{DSO}, s \in S^D} DispatchDA_i \cdot \lambda_{i,s}^{D1} + \sum_{i \in I^{DSO}, s \in S^D} D_i^p \cdot \lambda_{i,s}^{D1} \\ - \sum_{i \in I^{DSO}, j \in I^{SUBS}, s \in S^D} DaDSO_s \cdot \lambda_{i,j,s}^{D2} + \sum_{i \in SLACK^s, s \in S^D} \lambda_{i,s}^{D3} + \sum_{i \in I^{DSO}, s \in S^D} D_i^q \cdot \lambda_{i,s}^{D4} \\ + \sum_{k \in K^{DSO}} P_k^+ \cdot \bar{\mu}_k^{up} + \sum_{k \in K^{DSO}} P_k^- \cdot \bar{\mu}_k^{dw} + \sum_{i \in I^{DSO}, j} F_{i,j}^{p,+} \cdot \bar{\mu}_{i,j}^p - \sum_{i \in I^{DSO}, j} F_{i,j}^{p,-} \cdot \underline{\mu}_{i,j}^p \\ + \sum_{i \in I^{DSO}, j} F_{i,j}^{q,+} \cdot \bar{\mu}_{i,j}^q - \sum_{i \in I^{DSO}, j} F_{i,j}^{q,-} \cdot \underline{\mu}_{i,j}^q + \sum_{i \in I^{DSO+}} (V^+)^2 \cdot \bar{\mu}_i^V - \sum_{i \in I^{DSO+}} (V^+)^2 \cdot \underline{\mu}_i^V \end{aligned} \tag{C.2}$$

C.2 Linearisation of the Lower Levels' Complementarity Conditions

In order to linearise the complementarity conditions, the Big-M technique is employed. Therefore, the complementarity conditions of the DSO's lower level (4.4i)-(4.4r) and TSO's lower level (4.5g)-(4.5n) are substituted by the formulation below. It is worth mentioning that some complementarity conditions are shared by both models, only changing the subsets applicable. These complementarity conditions can be unified in one single constraint. This is done in (C.3a)-(C.3x).

$$-p_k^{up} + P_k^+ \geq 0 \quad \forall k \tag{C.3a}$$

$$\bar{\mu}_k^{up} \geq 0 \quad \forall k \tag{C.3b}$$

$$-p_k^{up} + P_k^+ \leq b_k^{01} \cdot M^{01} \quad \forall k \tag{C.3c}$$

$$\bar{\mu}_k^{up} \leq (1 - b_k^{01}) \cdot M^{01} \quad \forall k \tag{C.3d}$$

$$p_k^{up} \geq 0 \quad \forall k \tag{C.3e}$$

$$\underline{\mu}_k^{up} \geq 0 \quad \forall k \tag{C.3f}$$

$$p_k^{up} \leq b_k^{02} \cdot M^{02} \quad \forall k \tag{C.3g}$$

$$\underline{\mu}_k^{up} \leq (1 - b_k^{02}) \cdot M^{02} \quad \forall k \tag{C.3h}$$

$$-p_k^{dw} + P_k^- \geq 0 \quad \forall k \tag{C.3i}$$

$$\bar{\mu}_k^{dw} \geq 0 \quad \forall k \tag{C.3j}$$

$$-p_k^{dw} + P_k^- \leq b_k^{03} \cdot M^{03} \quad \forall k \tag{C.3k}$$

$$\bar{\mu}_k^{dw} \leq (1 - b_k^{03}) \cdot M^{03} \quad \forall k \tag{C.3l}$$

$$p_k^{dw} \geq 0 \quad \forall k \tag{C.3m}$$

$$\underline{\mu}_k^{dw} \geq 0 \quad \forall k \tag{C.3n}$$

$$p_k^{dw} \leq b_k^{04} \cdot M^{04} \quad \forall k \tag{C.3o}$$

$$\underline{\mu}_k^{dw} \leq (1 - b_k^{04}) \cdot M^{04} \quad \forall k \tag{C.3p}$$

$$-f_{i,j}^p + F_{i,j}^{p,+} \geq 0 \quad \forall (i,j) \in L \tag{C.3q}$$

$$\bar{\mu}_{i,j}^p \geq 0 \quad \forall (i,j) \in L \tag{C.3r}$$

$$-f_{i,j}^p + F_{i,j}^{p,+} \leq b_k^{05} \cdot M^{05} \quad \forall (i,j) \in L \tag{C.3s}$$

$$\bar{\mu}_{i,j}^p \leq (1 - b_k^{05}) \cdot M^{05} \quad \forall (i,j) \in L \tag{C.3t}$$

$$-F_{i,j}^{p,-} + f_{i,j}^p \geq 0 \quad \forall (i,j) \in L \tag{C.3u}$$

$$\underline{\mu}_{i,j}^p \geq 0 \quad \forall (i,j) \in L \tag{C.3v}$$

$$-F_{i,j}^{p,-} + f_{i,j}^p \leq b_k^{06} \cdot M^{06} \quad \forall (i,j) \in L \tag{C.3w}$$

$$\underline{\mu}_{i,j}^p \leq (1 - b_k^{06}) \cdot M^{06} \quad \forall (i,j) \in L \tag{C.3x}$$

$$-f_{i,j}^q + F_{i,j}^{q,+} \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{C.3y}$$

$$\bar{\mu}^q_{i,j} \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{C.3z}$$

$$-f^q_{i,j} + F^{q,+}_{i,j} \leq b^{07}_k \cdot M^{07} \quad \forall (i,j) \in L, i \in I^{DSO} \tag{C.3aa}$$

$$\bar{\mu}^q_{i,j} \leq (1 - b^{07}_k) \cdot M^{07} \quad \forall (i,j) \in L, i \in I^{DSO} \tag{C.3ab}$$

$$-F^{q,-}_{i,j} + f^q_{i,j} \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{C.3ac}$$

$$\underline{\mu}^q_{i,j} \geq 0 \quad \forall (i,j) \in L, i \in I^{DSO} \tag{C.3ad}$$

$$-F^{q,-}_{i,j} + f^q_{i,j} \leq b^{08}_k \cdot M^{08} \quad \forall (i,j) \in L, i \in I^{DSO} \tag{C.3ae}$$

$$\underline{\mu}^q_{i,j} \leq (1 - b^{08}_k) \cdot M^{08} \quad \forall (i,j) \in L, i \in I^{DSO} \tag{C.3af}$$

$$-w_i + (V^+)^2 \geq 0 \quad \forall i \in I^{DSO+} \tag{C.3ag}$$

$$\bar{\mu}^V_i \geq 0 \quad \forall i \in I^{DSO+} \tag{C.3ah}$$

$$-w_i + (V^+)^2 \leq b^{09}_k \cdot M^{09} \quad \forall i \in I^{DSO+} \tag{C.3ai}$$

$$\bar{\mu}^V_i \leq (1 - b^{09}_k) \cdot M^{09} \quad \forall i \in I^{DSO+} \tag{C.3aj}$$

$$-(V^-)^2 + w_i \geq 0 \quad \forall i \in I^{DSO+} \tag{C.3ak}$$

$$\underline{\mu}^V_i \geq 0 \quad \forall i \in I^{DSO+} \tag{C.3al}$$

$$-(V^-)^2 + w_i \leq b^{10}_k \cdot M^{10} \quad \forall i \in I^{DSO+} \tag{C.3am}$$

$$\underline{\mu}^V_i \leq (1 - b^{10}_k) \cdot M^{10} \quad \forall i \in I^{DSO+} \tag{C.3an}$$

$$-\theta_i + \theta^+ \geq 0 \quad \forall i \in I^{TSO+} \tag{C.3ao}$$

$$\bar{\mu}^\theta_i \geq 0 \quad \forall i \in I^{TSO+} \tag{C.3ap}$$

$$-\theta_i + \theta^+ \leq b_k^{11} \cdot M^{11} \quad \forall i \in I^{TSO+} \tag{C.3aq}$$

$$\bar{\mu}_i^{\theta} \leq (1 - b_k^{11}) \cdot M^{11} \quad \forall i \in I^{TSO+} \tag{C.3ar}$$

$$\theta^+ + \theta_i \geq 0 \quad \forall i \in I^{TSO+} \tag{C.3as}$$

$$\underline{\mu}_i^{\theta} \geq 0 \quad \forall i \in I^{TSO+} \tag{C.3at}$$

$$\theta^+ + \theta_i \leq b_k^{12} \cdot M^{12} \quad \forall i \in I^{TSO+} \tag{C.3au}$$

$$\underline{\mu}_i^{\theta} \leq (1 - b_k^{12}) \cdot M^{12} \quad \forall i \in I^{TSO+} \tag{C.3av}$$

D Case Study Data

Scalar	Value
SB	100
$\theta^{+,-}$	± 1.5
PF	0.95
V^{+}	1.1
V^{-}	0.9
$IntPrice_s^{+}$	1000[1]

Table D.1: Scalars for both Stylised and 102-Bus Case Studies

D.1 Stylised Case Study

i	j	$R_{i,j}$ **(p.u.)**	$X_{i,j}$ **(p.u.)**	$F_{i,j}^{p,+}$ **(MW)**
T1	T2	0.00281	0.0281	400
T2	T3	0.00304	0.0304	400
T3	T4	0.00064	0.0064	400
T1	T4	0.00108	0.0108	400
T4	T5	0.00297	0.0297	400
T5	T1	0.00297	0.0297	400
T2	S1	0.005	0.0344	400
D1002	S1	0.003	0.006	10
D1002	D1003	0.003	0.006	6

Table D.2: Branch data for Stylized Case Study

[1]For the Fragmented-Strategic CS

i	s	$SLACK$	D_i^p (MW)	D_i^q (Mvar)	$DispatchDA_i$ (MW)
T1	TSO		0		
T2	TSO		100		
T3	TSO		300		1,010
T4	TSO		600		
T5	TSO		0		
D1002	D1	DSO	0		
D1003	D1		10	3.287	
S1		TSO			

Table D.3: Bus data for Stylised Case Study

k	i	s	P_k^- (MW)	P_k^+ (MW)	Bid_k^{dw} (€/MWh)	Bid_k^{up} (€/MWh)
G3	T3	TSO	500	500	50	50
G4	T4	TSO	300	300	20	20
FSP1	D1002	DSO	2	0	10	10
FSP2	D1002	DSO	2	0	30	30
FSP3	D1003	DSO	5	5	60	60

Table D.4: FSP data for Stylised Case Study

D.2 102-bus Case Study

k	i	s	P_k^- (MW)	P_k^+ (MW)	Bid_k^{dw} (€/MWh)	Bid_k^{up} (€/MWh)
KT2	2	TSO	60	60	21	21
KT22	22	TSO	70	70	35	35
KT27	27	TSO	50	50	48	48
KT23	23	TSO	40	40	25	25
KT13	13	TSO	45	45	55	55
K1009	1009	DSO 1	1	1	34	68
K1020	1020	DSO 1	1	1	59	118
K1021	1021	DSO 1	1	1	41	81
K1022	1022	DSO 1	1	1	33	66
K1024	1024	DSO 1	1	1	56	111
K1025	1025	DSO 1	1	1	67	134
K2004	2004	DSO 2	1	1	68	136
K2008	2008	DSO 2	1	1	47	93
K2009	2009	DSO 2	1	1	65	130
K2022	2022	DSO 2	1	1	74	147

continued …

k	i	s	P_k^- **(MW)**	P_k^+ **(MW)**	Bid_k^{dw} **(€/MWh)**	Bid_k^{up} **(€/MWh)**
K2025	2025	DSO 2	1	1	71	141
K3004	3004	DSO 3	1	1	73	146
K3005	3005	DSO 3	1	1	52	104
K3007	3007	DSO 3	1	1	38	75
K3009	3009	DSO 3	1	1	44	88
K4002	4002	DSO 4	1	1	45	89
K4003	4003	DSO 4	1	1	37	73
K4020	4020	DSO 4	1	1	72	143
K4023	4023	DSO 4	1	1	50	99
K4026	4026	DSO 4	1	1	29	57
K3025	3025	DSO 3	0	3	220	439
K1006	1006	DSO 1	0	3	64	128

Table D.5: FSP data for the 102-Bus Case Study

i	j	$R_{i,j}$ **(p.u.)**	$X_{i,j}$ **(p.u.)**	$F_{i,j}^{p,+}$ **(MW)**
1	2	0.02	0.06	130
1	3	0.05	0.19	130
2	4	0.06	0.17	65
3	4	0.01	0.04	130
2	5	0.05	0.2	130
2	6	0.06	0.18	65
4	6	0.01	0.04	90
5	7	0.05	0.12	70
6	7	0.03	0.08	130
6	8	0.01	0.04	**23**
6	9	0	0.21	65
6	10	0	0.56	32
9	11	0	0.21	65
9	10	0	0.11	65
4	12	0	0.26	65
12	13	0	0.14	65
12	14	0.12	0.26	32
12	15	0.07	0.13	32
12	16	0.09	0.2	32
14	15	0.22	0.2	16
16	17	0.08	0.19	16
15	18	0.11	0.22	16

continued ...

i	j	$R_{i,j}$ (p.u.)	$X_{i,j}$ (p.u.)	$F_{i,j}^{p,+}$ (MW)
18	19	0.06	0.13	16
19	20	0.03	0.07	32
10	20	0.09	0.21	32
10	17	0.03	0.08	32
10	21	0.03	0.07	32
10	22	0.07	0.15	32
21	22	0.01	0.02	32
15	23	0.1	0.2	16
22	24	0.12	0.18	16
23	24	0.13	0.27	16
24	25	0.19	0.33	16
25	26	0.25	0.38	16
25	27	0.11	0.21	16
28	27	0	0.4	65
27	29	0.22	0.42	16
27	30	0.32	0.6	16
29	30	0.24	0.45	16
8	28	0.06	0.2	32
6	28	0.02	0.06	32
1001	1002	0.0431	0.1204	4
1002	1003	0.0601	0.1677	4
1003	1004	0.0316	0.0882	**2**
1004	1005	0.0896	0.2502	4
1005	1006	0.0295	0.0824	1.5
1006	1007	0.172	0.212	1.5
1007	1008	0.407	0.3053	1.5
1002	1009	0.1706	0.2209	1.5
1001	1020	0.291	0.3768	4
1020	1021	0.2222	0.2877	4
1021	1022	0.4803	0.6218	1.5
1021	1023	0.3985	0.516	1.5
1023	1024	0.291	0.3768	1.5
1023	1025	0.3727	0.4593	1.5
1025	1026	0.1104	0.136	1.5
1001	111	0.0	0.001	6
111	110	0.0312	0.6753	6
2	110	0.005	0.0344	6
2001	2002	0.0431	0.1204	4
2002	2003	0.0601	0.1677	4
2003	2004	0.0316	0.0882	4
2004	2005	0.0896	0.2502	4

continued ...

i	j	$R_{i,j}$ (p.u.)	$X_{i,j}$ (p.u.)	$F^{p,+}_{i,j}$ (MW)
2005	2006	0.0295	0.0824	1.5
2006	2007	0.172	0.212	1.5
2007	2008	0.407	0.3053	1.5
2002	2009	0.1706	0.2209	1.5
2001	2020	0.291	0.3768	4
2020	2021	0.2222	0.2877	4
2021	2022	0.4803	0.6218	1.5
2021	2023	0.3985	0.516	1.5
2023	2024	0.291	0.3768	1.5
2023	2025	0.3727	0.4593	1.5
2025	2026	0.1104	0.136	1.5
2001	211	0.0	0.001	6
211	210	0.0312	0.6753	6
7	210	0.005	0.0344	6
3001	3002	0.0431	0.1204	4
3002	3003	0.0601	0.1677	4
3003	3004	0.0316	0.0882	4
3004	3005	0.0896	0.2502	4
3005	3006	0.0295	0.0824	1.5
3006	3007	0.172	0.212	1.5
3007	3008	0.407	0.3053	1.5
3002	3009	0.1706	0.2209	1.5
3001	3020	0.291	0.3768	4
3020	3021	0.2222	0.2877	4
3021	3022	0.4803	0.6218	1.5
3021	3023	0.3985	0.516	**0.75**
3023	3024	0.291	0.3768	1.5
3023	3025	0.3727	0.4593	1.5
3025	3026	0.1104	0.136	1.5
3001	311	0.0	0.001	6
311	310	0.0312	0.6753	6
12	310	0.005	0.0344	6
4001	4002	0.0431	0.1204	4
4002	4003	0.0601	0.1677	4
4003	4004	0.0316	0.0882	4
4004	4005	0.0896	0.2502	4
4005	4006	0.0295	0.0824	1.5
4006	4007	0.172	0.212	1.5
4007	4008	0.407	0.3053	1.5
4002	4009	0.1706	0.2209	1.5
4001	4020	0.291	0.3768	4

continued ...

i	j	$R_{i,j}$ (p.u.)	$X_{i,j}$ (p.u.)	$F_{i,j}^{p,+}$ (MW)
4020	4021	0.2222	0.2877	4
4021	4022	0.4803	0.6218	1.5
4021	4023	0.3985	0.516	1.5
4023	4024	0.291	0.3768	1.5
4023	4025	0.3727	0.4593	1.5
4025	4026	0.1104	0.136	1.5
4001	411	0.0	0.001	6
411	410	0.0312	0.6753	6
30	410	0.005	0.0344	6

Table D.6: Branch data for 102-Bus Case Study.

i	s	$SLACK$	D_i^p (MW)	D_i^q (Mvar)	$DispatchDA_i$ (MW)
1	TSO	TSO	0	0	36.2
2	TSO		9.85	0	49.1
3	TSO		2.4	0	
4	TSO		7.6	0	
5	TSO		0	0	
6	TSO		0	0	
7	TSO		10.95	0	
8	TSO		30	0	
9	TSO		0	0	
10	TSO		5.8	0	
11	TSO		0	0	
12	TSO		0	0	
13	TSO		0	0	14.13
14	TSO		6.2	0	
15	TSO		8.2	0	
16	TSO		3.5	0	
17	TSO		9	0	
18	TSO		3.2	0	
19	TSO		9.5	0	
20	TSO		2.2	0	
21	TSO		17.5	0	
22	TSO		0	0	21.24
23	TSO		3.2	0	13.82
24	TSO		8.7	0	

continued …

i	s	$SLACK$	D_i^p **(MW)**	D_i^q **(Mvar)**	$DispatchDA_i$ **(MW)**
25	TSO		0	0	
26	TSO		3.5	0	
27	TSO		0	0	32.41
28	TSO		0	0	
29	TSO		2.4	0	
30	TSO		0	0	
110	(interface)	DSO 1	0	0	
111	DSO 1		0	0	
1001	DSO 1		0	0	
1002	DSO 1		0.1	0.06	
1003	DSO 1		0.2	0.125	
1004	DSO 1		0.75	0.465	
1005	DSO 1		1.5	1.13	
1006	DSO 1		0.4	0.25	
1007	DSO 1		0.1	0.06	
1008	DSO 1		0.5	0.31	
1009	DSO 1		0.25	0.155	
1020	DSO 1		0.5	0.31	
1021	DSO 1		0.15	0.095	
1022	DSO 1		0.1	0.06	
1023	DSO 1		0.4	0.25	
1024	DSO 1		0.25	0.155	
1025	DSO 1		0.5	0.31	
1026	DSO 1		0.1	0.06	
210	(interface)	DSO 2	0	0	
211	DSO 2		0	0	
2001	DSO 2		0	0	
2002	DSO 2		0.1	0.06	
2003	DSO 2		0.2	0.125	
2004	DSO 2		0.75	0.465	
2005	DSO 2		1.5	1.13	
2006	DSO 2		0.4	0.25	
2007	DSO 2		0.1	0.06	
2008	DSO 2		0.5	0.31	
2009	DSO 2		0.25	0.155	
2020	DSO 2		0.5	0.31	
2021	DSO 2		0.15	0.095	
2022	DSO 2		0.1	0.06	
2023	DSO 2		0.4	0.25	
2024	DSO 2		0.25	0.155	

continued …

i	s	$SLACK$	D_i^p (MW)	D_i^q (Mvar)	$DispatchDA_i$ (MW)
2025	DSO 2		0.5	0.31	
2026	DSO 2		0.1	0.06	
310	(interface)	DSO 3	0	0	
311	DSO 3		0	0	
3001	DSO 3		0	0	
3002	DSO 3		0.1	0.06	
3003	DSO 3		0.2	0.125	
3004	DSO 3		0.75	0.465	
3005	DSO 3		1.5	1.13	
3006	DSO 3		0.4	0.25	
3007	DSO 3		0.1	0.06	
3008	DSO 3		0.5	0.31	
3009	DSO 3		0.25	0.155	
3020	DSO 3		0.5	0.31	
3021	DSO 3		0.15	0.095	
3022	DSO 3		0.1	0.06	
3023	DSO 3		0.4	0.25	
3024	DSO 3		0.25	0.155	
3025	DSO 3		0.5	0.31	
3026	DSO 3		0.1	0.06	
410	(interface)	DSO 4	0	0	
411	DSO 4		0	0	
4001	DSO 4		0	0	
4002	DSO 4		0.1	0.06	
4003	DSO 4		0.2	0.125	
4004	DSO 4		0.75	0.465	
4005	DSO 4		1.5	1.13	
4006	DSO 4		0.4	0.25	
4007	DSO 4		0.1	0.06	
4008	DSO 4		0.5	0.31	
4009	DSO 4		0.25	0.155	
4020	DSO 4		0.5	0.31	
4021	DSO 4		0.15	0.095	
4022	DSO 4		0.1	0.06	
4023	DSO 4		0.4	0.25	
4024	DSO 4		0.25	0.155	
4025	DSO 4		0.5	0.31	
4026	DSO 4		0.1	0.06	

Table D.7: Bus data for 102-Bus Case Study

Acronyms

AC	Alternating Current
ADMM	Alternating Direction Method of Multipliers
aFRR	automatic Frequency Restoration Reserve
AS	Ancillary Service
B2B	Business-to-Business
B2C	Business-to-Client
BM	Business Model
BRP	Balance Responsible Party
BSP	Balancing Service Provider
CACM	Capacity Allocation and Congestion Management
CAPEX	Capital Expenditure
CEP	Clean Energy Package
CHP	Combined Heat and Power
CM	Central Market
CS	Coordination Scheme
cVPP	Commercial Virtual Power Plant
DA	Day-Ahead
DC	Direct Current
DER	Distributed Energy Resource
DG	Distributed Generation
DLMP	Distribution Locational Marginal Price
DR	Demand Response
DSO	Distribution System Operator
DSP	Data Service Provider
EBGL	Electricity Balancing Guideline
EHV	Extra High-Voltage
ESCO	Energy Service Company
ESS	Energy Storage System
EU	European Union
EV	Electric Vehicle
FCR	Frequency Containment Reserves
FOR	Flexibility Operating Region
FSP	Flexibility Service Provider
GAMS	General Algebraic Modeling System
GCT	Gate-Closure Time
HV	High-Voltage

ICT	Information and Communications Technology
ID	Intraday
ISO	Independent System Operator
KKT	Karush–Kuhn–Tucker
LFM	Local Flexibility Market
LM	Local Market
LP	Linear Programming
LV	Low-Voltage
MBMA	Meter-Before-Meter-After
mFRR	manual Frequency Restoration Reserve
MILP	Mixed Integer Linear Programming
ML	Machine Learning
MM	Market Model
MO	Market Operator
MPEC	Mathematical Program with Equilibrium Constraint
MS	Member State (EU)
MV	Medium-Voltage
NCQCP	Nonconvex Quadratically Constrained Programming
NLP	Nonlinear Programming
NSF	Non-Served Flexibility
NTC	Net Transfer Capacity
OPEX	Operational Expenditure
OPF	Optimal Power Flow
PTDF	Power Transfer Distribution Factor
PV	Photovoltaic
QP	Quadratic Programming
R	Resistance
RES	Renewable Energy Source
RPI	Retail Price Index
RR	Replacement Reserve
S-DL	Service-Dominant Logic
SCADA	Supervisory Control And Data Acquisition
SDA	Same-Day Adjustment
SDP	Semidefinite Programming
SO	System Operator
SoC	State of Charge
SOCP	Second-Order Cone Programming
SOGL	System Operation Guideline
TOTEX	Total Expenditure
TSO	Transmission System Operator
tVPP	Technical Virtual Power Plant
UC	Use Case
UK	United Kingdom
V2G	Vehicle-to-Grid

VIU	Vertically Integrated Utility
VPP	Virtual Power Plant
WACC	Weighted Average Cost of Capital
X	Reactance
XBID	European Cross-Border Intraday

NOMENCLATURE

Provisional preamble.

Indexes:

$e \in E$	iteration index (used for Benders' decomposition).
$g \in G$	generator.
$h \in H$	hour.
$i, j, ii \in N$	bus.
$k \in K$	Flexibility Service Provider (FSP).
$lv \in LS$	levels of subscription of the interface.
$s, s' \in S$	System Operator (SO).
$t \in T$	system operator type; $\in (TSO, DSO)$.
$z, zz \in Z$	bidding zones.

Sets:

$ESS(k)$	Subset of FSPs that are Energy Storage Systems (ESSs).
$Front^{DSO}(i)$	buses i that are at the frontier of a DSO grid (i.e. connected to a substation)
$Front^{TSO}(i)$	buses i that are at the frontier of a TSO grid (i.e. connected to a substation)
$I^{DSO+}(i)$	Subset of buses i that belong to DSO or is a interface bus (substation).
$I^{DSO}(i)$	Subset of buses i that belong to a DSO.
$I^{SUBS}(i)$	Subset of buses i that are an interface bus (substation).
$I^{TSO+}(i)$	Subset of buses i that belong to TSO or is a interface bus (substation).
$I^{TSO}(i)$	Subset of buses i that belong to a TSO.
$IF(i,k)$	Set of FSPs k connected at bus i.
$IG(i,g)$	Set of generators g connected at bus i.
$INTER(s,i,s')$	Set establishing that SO s is connected to SO s' through bus (substation) i.
$INTER$	Set of interface buses ($INTER \subset N$).
$Intercon(i,j)$	Set that relate a frontier bus i from a DSO ($i \in Front^{DSO}$) to a frontier bus j from a TSO ($j \in Front^{TSO}$)

$IS(i,s)$	Set of buses i belonging to System Operator s.
$IZ(z,zz)$	Set of interconnections between bidding zones.
$K^{DSO}(k,s)$	Subset of FSPs k that are connected to a DSO s.
$K^{TSO}(k,s)$	Subset of FSPs k that are connected to a TSO s.
$L(i,j)$	Set of lines from bus i to bus j.
$RES(g)$	Subset of generators g that are Renewable Energy Sources (RESs).
$S^D(s)$	Subset of SOs s that are DSOs.
$S^T(s)$	Subset of SOs s that are TSOs.
$SLACK^s(i)$	Subset of buses i denoting the slack bus for SO s
$SUBS$	Set of substations buses ($SUBS \subset N$).
$TS(t,s)$	Set of correspondence between t and s.
$ZG(g,z)$	Set of generators g in bidding zone z.
$ZN(i,z)$	Set of buses i in bidding zone z.

Parameters:

Δ_e	Auxiliary parameter of the Benders decomposition algorithm. [binary]
θ_i^+/θ_i^-	Maximum/minimum phase angle θ for bus i. [radians]
Bid_g	Bid of gen. g in the Day-Ahead (DA) market. [€$/MWh$]
Bid_k^{dw}	Bid of FSP k for downward activation in the flexibility market(s). [€$/MWh$]
Bid_k^{up}	Bid of FSP k for upward activation in the flexibility market(s). [€$/MWh$]
$CNSF$	Cost of non-served flexibility. [€$/MWh$]
$CSubs_{i,lv}$	Cost per subscription level lv in bus i. [€$/MWh$]
Cyc_g	Cycling cost of generator g. [€]
D_i^p	Active power demand at bus i. [MW]
D_i^q	Reactive power demand for bus i. [Mvar]
$D_{i,h}$	Demand (active power) at bus i in hour h. [MW]
$DaDSO_s$	Aggregated demand for DSO s. [MW]
$DispatchDA_{i,h}$	Total generation cleared in the DA market produced in bus i during hour h. [MW]
$DispatchDA_i$	Total generation cleared in the Day-Ahead market produced at bus i. [MW]
$DispatchFSP_{k,h}$	Parameter that captures the activation of FSP k in the Local Flexibility Market (LFM). [binary]
$DRMax$	Number of hours that a flexible load FSP can provide flexibility. [hours]

$DSOdemand_s$ Aggregated demand for DSO s at the interface substation. [MW]

EF ESS efficiency. [p.u.]

$F_{i,j}^{p,+}/F_{i,j}^{p,-}$ Max./min. active power flow of line (i,j). [MW]

$F_{i,j}^{q,+}/F_{i,j}^{q,-}$ Max./min. reactive power flow of line (i,j). [Mvar]

$IE_{e,i\in Front^{TSO}}^{ie\_TSO}$ Parameter computed from ie^* in iteration e of the Benders algorithm.

$Imb_{i,h}$ Imbalance in bus i in hour h. [MW]

$Impact_i$ Average of distribution network PTDFs for substation i. [p.u.]

$IntPrice_s^{+,-}$ Upper/lower limit for the interface price for SO s. [€$/MWh$]

$IntPrice_s$ Interface price (parameter) for SO s. [€$/MWh$]

$LimitFactor^{cap,floor}$ Cap and floor factor for interface price. [p.u.]

M^n Large enough parameter number n from Big-M implementation.

$MaxFlex_k^+$ Maximum upward flexibility capacity in relation to the DA dispatch for RES FSP k. [p.u.]

$MaxFlex_k^-$ Maximum downward flexibility capacity in relation to the DA dispatch for RES FSP k. [p.u.]

$MinBidSize$ Minimum bid size. [MW]

$MinDispatch_g$ Minimum technical dispatch of generator g. [p.u.]

$Minup_k$ Minimum up time for FSP k. [hours]

$NTC_{z,zz}^+$ Upper bound for Net Transfer Capacity (NTC) between bidding zones z, zz. [MW]

$NTC_{z,zz}^-$ Lower bound for Net Transfer Capacity (NTC) between bidding zones z, zz. [MW]

P_g^+ Maximum output of generator g. [MW]

$P_{k,h}^+/P_{k,h}^-$ Maximum/minimum output of FSP k in hour h. [MW]

P_k^+/P_k^- Maximum/minimum output of FSP k. [MW]

$PDA_{k,h}$ Quantity dispatched in the DA for FSP k in hour h. [MW]

PF Fixed power factor for all FSPs connected to distribution networks. [p.u.]

$PTDF_{i,j,ii}$ Power Transfer Distribution Factor (PTDF) of bus ii over line (i,j). [p.u.]

$R_{i,j}$ Resistance of line (i,j). [p.u.]

$ResProfile_{g,h}$ Profile for RES g in hour h. [p.u.]

SB Base Power. [MVA]

$SoC_{k,h=1}^{init}$ Initial State-of-Charge (SoC) of ESS k in hour 1. [p.u.]

$V^{+,-}$ Maximum/minimum voltage limits. [p.u.]

$X_{i,j}$ Reactance of line (i, j). [p.u.]

Z_e^{Sub} Value of the objective function of the Subproblem of the Benders decomposition. [€]

Variables:

$\bar{\mu}^n$ Dual variable of inequality contraint setting an upper bound on variable indicated by n. Indexes according to the constraint.

λ^{Dn} Dual variable of equality contraint n belonging to the DSO lower level model. Indexes according to the constraint.

λ^{Tn} Dual variable of equality contraint n belonging to the TSO lower level model. Indexes according to the constraint.

$\pi_{i \in Front^{TSO}}^{ie\_TSO}$ Dual variable of the imports/exports constraints in the Benders implementation.

$\theta^{BENDERS}$ Auxiliary variable of the Benders decomposition algorithm.

$\theta_{i,h}$ Angle θ at bus i in hour h. [radians]

θ_i Angle θ at bus i. [radians]

$\underline{\mu}^n$ Dual variable of inequality contraint setting a lower bound on variable indicated by n. Indexes according to the constraint.

b^n Binary variable number n from Big-M implementation. Indexes according to the constraint. [binary]

$bcha_{k,h}$ Binary variable for the charging of ESS k in hour h. [binary]

$bdis_{k,h}$ Binary variable for the discharging of ESS k in hour h. [binary]

$dda_{i,h}$ Total generation cleared in the DA market produced in bus i during hour h. [MW]

$f_{i,j}^p$ Active power flow over line connecting buses i and j. [MW]

$f_{i,j}^q$ Reactive power flow over line (i, j). [Mvar]

$f_{i,j,h}$ Active power flow over line connecting buses i and j during hour h. [MW]

$fexport_{i,h}$ Power exported from the transmission grid to the distribution grid at bus i in hour h. [MW]

$fimport_{i,h}$ Power imported by the distribution grid from the transmission grid at bus i in hour h. [MW]

$flexess_{k,h}^{dw}$ Auxiliary variable for the implementation of the storage logic.

$fsubs_{i,h}$ Power leaving or entering substation i in hour h. [MW]

ie_i Quantity imported or exported from a frontier bus i. [MW]

$intprice_s$ Interface price (variable; bilevel) for SO s (bilevel model). [€$/MWh$]

$lvsubs_{i,lv,h}$ Level lv of use of subscription power at the at bus i in hour h. [MW]

$nsf_{i,h}^{dw}$ Non-served downward flexibility in bus i in hour h. [MW]

$nsf^{up}_{i,h}$	Non-served upward flexibility in bus i in hour h. [MW]
$p_{k,h}$	Quantity of flexibility cleared for FSP k in hour h in absolute value [MW]
$p^{dw}_{k,h}$	Quantity of downward flexibility cleared for FSP k in hour h (active power). [MW]
$p^{up}_{k,h}$	Quantity of upward flexibility cleared for FSP k in hour h (active power). [MW]
p^{dw}_{k}	Quantity of downward flexibility cleared for FSP k. [MW]
p^{up}_{k}	Quantity of upward flexibility cleared for FSP k. [MW]
$pcha_{k,h}$	Power being charged from ESS k in hour h. [p.u.]
$pda_{g,h}$	Quantity cleared in the DA market for generator g in hour h. [MW]
$pdis_{k,h}$	Power being discharged from ESS k in hour h. [p.u.]
$pfsub_{i,j,h}$	Impact of bus j on the power flow over bus i in hour h. [MW]
$pmax_{g,h}$	Maximum generation of g in hour h within the unit commitment problem. [MW]
q_k	Reactive power generated/consumed by FSP k [Mvar]
$sd_{g,h}$	Shutdown of generator g in hour h. [binary]
$slackQ_{i,j}$	Variable to accommodate the reactive power coming from the transmission network over line (i, j) [Mvar]
$soc_{k,h}$	SoC of ESS k in hour h. [p.u.]
$su_{g,h}$	Start-up of generator g in hour h. [binary]
$subscost_{s,h}$	Total cost for surpassing the subscription cost in substation s in hour h. [€$/MWh$]
$tc_{z,zz,h}$	Transfer between bidding zones z and zz in hour h. [MW]
$uc_{g,h}$	Unit commitment status of generator g in hour h. [binary]
$uc^{dw}_{k,h}$	Binary variable for the downward activation of FSP k in hour h. [binary]
$uc^{up}_{k,h}$	Binary variable for the upward activation of FSP k in hour h. [binary]
$vd_{s,h}$	Virtual demand of DSO s in hour h. [MW]
w_i	Square of the voltage in bus i. [p.u.]

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