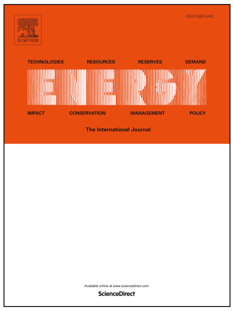

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Co-optimizing Energy and Reserve Interconnection Capacity in Coupled EU Electricity Markets

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Abstract

The European Union Internal Electricity Market is undergoing major reforms to support the transition to a fully decarbonized energy system by 2050, where non-dispatchable renewable energy sources play a central role. To enhance market efficiency, renewable energy sources integration, and power system balancing, the European Union promotes increased cross-border interconnection and cooperation among Member States. This paper reviews existing literature and market models addressing multi-zone interconnection capacity allocation and proposes a novel inter-zonal co-optimization mechanism for the joint allocation of energy and automatic balancing reserve capacity based on system cost minimization. Unlike previous approaches that treat energy and reserve coordination separately or sequentially, this study introduces a unified optimization framework that captures the interdependencies of intra- and inter-zonal dispatch. The proposed mechanism is implemented within the CEVESA market model and applied to a realistic Iberian case study, assessing its economic and operational impacts under varying interconnection capacity scenarios. Results show that while energy coordination alone achieves significant cost reductions, joint coordination of energy and reserves delivers further efficiency gains, reduces reserve price volatility, and enhances cross-border system flexibility.

Keywords: electricity market, interconnections capacity allocation, market coupling, balancing reserves coordination.

	Sets
Z	Zones
T	Thermal units
M	Hydro units
R	Renewable units
	Indexes
z	Zones
h	Hours
w	Weeks

u	Generation units
l	Interconnection line

Subsets

H_w	Hours belonging to week *w*
U_z	Units belonging to zone *z*
L_z^{FROM}	Lines outgoing from zone *z*
L_z^{TO}	Lines incoming into zone *z*

Parameters

$D_{z,h}$	Electricity demand [MWh]
$UR_{z,h}$	Upward reserve needs [MW]
$DR_{z,h}$	Downward reserve needs [MW]
$NTC_{l,h}^{FRO}$	Net transfer capacity available for energy and reserve trade in reverse direction for line *l* [MW]
NTC_z^{TO}	Net transfer capacity available for energy and reserve trade in direct sense for line *l* [MW]
P_u^{INS}	Installed capacity [MW]
P_u^{MIN}	Technical minimum [MW]
C_u^V	Variable cost including CO_2 emission cost [€/MWh]
C_u^{ON}	Start-up cost [€]
C_u^{OFF}	Shutdown cost [€]
URG_u	Upward ramp [MWh/h]
DRG_u	Downward ramp [MWh/h]
$Q_{M,w}^E$	Weekly target of hydro production per technology [MWh]
$Q_{u,w}^E$	Weekly target of hydro production per unit [MWh]
$Q_{u,w}^{UR}$	Weekly upper reserve [MW]
$Q_{u,w}^{DR}$	Weekly down reserve [MW]
EF_u	Pumping efficiency [%]
$Q_{u,w}^{MAX}$	Maximum weekly production [MWh]
$Q_{u,w}^{MIN}$	Minimum weekly production [MWh]
$Q_{u,h}^R$	Available renewable generation [MWh]
TR	Secondary reserve time response [h]

Free Variables

$e_{l,h}$	Net transfer capacity allocated for trading energy through line *l* [MWh]
$ur_{l,h}$	Net transfer capacity allocated for providing upward reserve throughline *l* [MW]
$dr_{l,h}$	Net transfer capacity allocated for providing downward reserve through line *l* [MW]

Positive Variables

$q_{u,h}$	Generated energy [MWh]

$qp_{u,h}$	Generated energy above the technical minimum [MWh]
$bh_{u,h}$	Pumped energy by hydro unit [MWh]
$sp_{u,h}$	Spillages from renewable units [MWh]
$ur_{z,h}^{need}$	Designated upward reserve needs [MW]
$dr_{z,h}^{need}$	Designated downward reserve needs [MW]
$ur_{u,h}$	Upward reserve of unit u [MW]
$dr_{u,h}$	Downward reserve of unit u [MW]

Binary Variables

$u_{u,h}$	Coupling variable
$y_{u,h}$	Start-up variable
$z_{u,h}$	Shutdown variable

Dual Variables

$\lambda_{z,h}^{e}$	Hourly energy market price [€/MWh]
$\lambda_{z,h}^{r}$	Hourly reserve price [€/MW]

1. Introduction

The European Union (EU) Common Rules for the Internal Electricity Market [1] are a step forward towards a unified EU electricity market to provide the most cost-effective way to ensure a secure and affordable energy supply. As far as the interconnections allow it, electricity will flow from less expensive generation areas to more expensive ones, increasing competition and maximizing social welfare at the European level. Similarly, ongoing reserve coordination mechanisms will also help to reduce the required intra-reserves by profiting from inter countries' compensation and from other countries' less costly reserves. Overall, these reserves coordination mechanisms increase markets liquidity, competition, and reduce the balancing cost at the EU level [2].

The relevance of these coordination mechanisms has increased with the ongoing transition of the European power system towards higher shares of renewable energy sources (RES) and higher degree of coordination among European biding zones. The growing penetration of variable and non-dispatchable generation, such as wind and solar power, has reduced the predictability of net load and increased the need for flexibility in both market operation and system balancing. In this context, cross-border interconnections are no longer important only for day-ahead energy exchanges, but also for the provision of balancing services that help maintain system security in real time. Their efficient use has therefore become a central issue in the design and operation of coupled electricity markets.

However, interconnection capacity is limited and must be efficiently shared among different commercial and operational purposes. On the one hand, allocating more transmission capacity to energy trading improves bidding zones prices convergence which reduce total generation costs across neighbouring zones. On the other hand, allocating part of that capacity for balancing services reduces reserve procurement costs, improve access to flexibility resources located in other countries, and avoid inefficient simultaneous activation of opposite balancing actions in adjacent systems. As a result, energy exchanges and reserve procurement are inherently interdependent, since both compete for the same cross-border transmission resources, leading to the trade-off of how much capacity should be allocated to each product.

This interdependence has become more relevant in the European context due to the progressive implementation of market coupling arrangements for energy and coordinated platforms for balancing services. While these mechanisms aim to increase overall efficiency, they also make more visible the need to represent consistently the interaction between energy dispatch, reserve allocation, and cross-border transmission usage. Treating these elements separately overlooks operational trade-offs, particularly in systems where interconnection capacity is scarce or where balancing needs are strongly affected by renewable variability. This is especially significant in market environments such as the Iberian system, where cross-border exchanges play an important role in the joint operation of neighbouring bidding zones.

Given this short initial introduction, the remainder of this introduction is structured as follows. Subsection 1.1 presents the European electricity market context and discusses the increasing relevance of cross-border coordination for energy and reserve. This conceptual introduction is key to understand the literature review made in in subsection 1.2 on how some of the main modelling approaches used in the literature represent these interactions, highlighting their main limitations, finally leading to subsection 1.3 that identifies the research gap motivating this work and summarizes the main contributions of this paper.

1.1 Review of the European Electricity Market

This subsection provides an overview of the European electricity market framework relevant to the joint allocation of interconnection capacity for energy and balancing reserves. It first introduces the institutional structure and policy objectives of the EU internal electricity market, establishing the broader context in which cross-border coordination takes place. It then reviews the main reserve cooperation mechanisms currently implemented by European TSOs, followed by a description of the key interconnection capacity concepts used in market operation. Finally, the section discusses the main methods for allocating transmission capacity to energy and reserve services and outlines the market coupling mechanism that enables coordinated cross-border energy trading in Europe. Together, these elements form the regulatory and technical background underpinning the modelling approach proposed in this paper.

1.1.1 European Market Structure and Objectives

The EU internal electricity market is changing at a fast rate as the decarbonization of the energy sector progresses [3], being the coordination among member states' Market and System Operators (MO and SO) one of the EU objectives to ensure a secure energy supply, affordable and fair to all market players [1]. Moreover, the increase in Distributed Generation (DG) is changing the traditional power system structure and therefore increasing the complexity of the power system balancing mechanisms [4].

Some of the main objectives of this internal EU market are: fair access to all parties, high-level consumer protection, and adequate levels of interconnection and generation capacity to improve liquidity and competition among EU members [5].

The day-ahead market in Europe is constituted by two-sided energy-only national auctions integrated into a single market with a market coupling mechanism among national markets. With the increasing integration of variable and non-dispatchable renewable electricity sources (RES), closer to real-time balancing mechanisms are needed to provide the flexibility increase the system requires. At the commercial level, these mechanisms are the local intraday markets and the EU coordinated continuous intraday markets (XBID [6]). At the regulated system operation level, these mechanisms include the national reserve markets and the EU mechanisms for coordinating these national reserve markets to compensate imbalances among national markets and to share more efficient reserves among countries. These coordination mechanisms prevent the simultaneous activation of opposite reserves by netting the needs and contributing to increasing reserves' market liquidity [7].

EU electricity markets coordination is based on a) the interconnections capacity allocation for energy and reserve, b) the market coupling mechanisms for energy markets coordination, and c) imbalances netting and balancing reserves coordination mechanisms.

Recent contributions in the literature increasingly focus on short-term cross-border market designs with detailed network representations, including flow-based capacity allocation methods. While these approaches are well suited to operational market clearing and congestion management over short horizons, they address a different modelling objective than long-term electricity market and system analyses. Long-term models typically aim to assess annual system costs, dispatch patterns, and reserve allocation efficiency using fully chronological simulations with intertemporal constraints such as Unit Commitment (UC). Within this modelling class, cross-border exchanges are commonly represented using zonal NTC constraints, consistent with large-scale European planning studies such as the ENTSO-E Ten-Year Network Development Plan (TYNDP) [8]. Flow-based formulations require detailed and time-consistent grid topology data and Power Transfer Distribution Factors, which are difficult to define reliably for planning-oriented analyses and would substantially increase computational complexity without commensurate gains in insight. For this reason, flow-based market coupling models are not directly comparable to the long-term approaches reviewed here and are therefore not addressed in detail. The focus of this work is instead on advancing long-term market modelling through improved coordination mechanisms under scalable and robust cross-border representations.

1.1.2 European Reserve Cooperation Mechanisms

TSOs ensure the system balance by controlling the frequency with the previously allocated and real-time available reserves. These balancing mechanisms are defined in [9] as the Frequency Containment Reserve (FCR), the Frequency Restoration Reserves with Automatic activation (aFRR), the Frequency Restoration Reserves with Manual activation (mFRR), and the Replacement Reserves (RR), also with manual activation. Reference [9] provides a detailed description of these balancing mechanisms.

To develop reserves coordination among the EU TSOs, the Market Committee of the European Network for Transmission System Operators for Electricity (ENTSO-E), responsible for ensuring the optimal management of EU networks [10], implemented several platforms such as: MARIE [11], TERRE [12], IN [13] and PICASSO [14]. Since the focus of this research is modelling the interconnection capacity allocation among energy and aFRR, MARIE and TERRE platforms, which coordinate mFRR and RR respectively, will not be addressed in this work.

The Imbalance Netting (IN) platform, developed as a part of the International Grid Control Cooperation (IGCC) project launched in 2010, is detailed in [13]. In this platform, the IN is a process agreed between TSOs of two or more areas to coordinate the aFRR and to avoid simultaneous activation of reserves in opposite directions in different zones. This process is based on the communication of the power-frequency control by each TSO. It is achieved by considering the activated FRR and the respective FRR control errors. Figure 1 shows how the aFRR demand of each zone is reported to the aFRR optimisation system, which returns a signal to the secondary controllers (participation), avoiding counter-activation of aFRR balancing energy and, therefore, optimising the aFRR use [13].

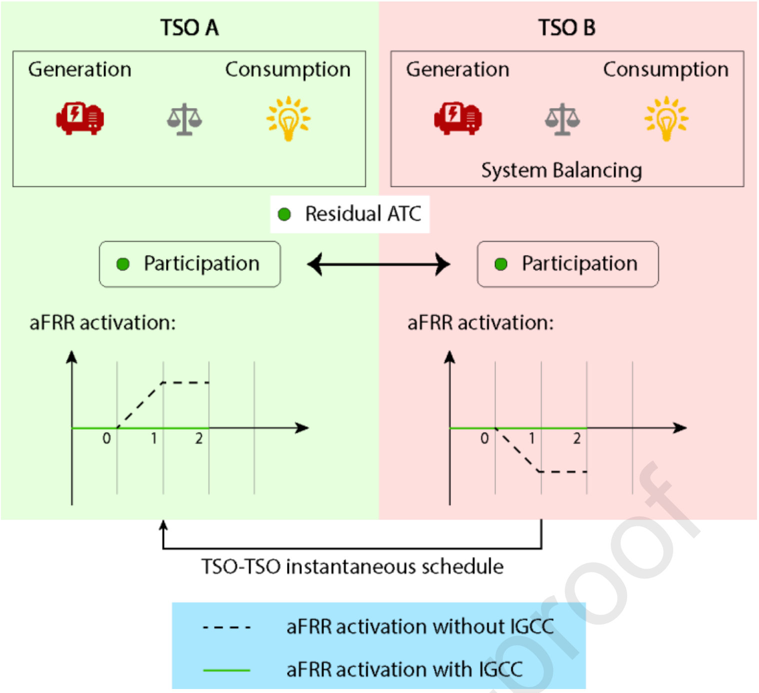

Figure 1 – Imbalance netting in IGCC [13].

PICASSO, the Platform for the International Coordination of the Automatic frequency restoration process and Stable System Operation [14], implements and operates a set of rules for balancing energy from national aFRR. Its main objectives [15] are: 1) the reduction of balancing costs by optimizing the aFRR activation, 2) the increase of the available balancing energy for each TSO, improving the security of supply and enabling a smoother integration of renewable energy, 3) the efficiency increase of the cross-border interconnections use after intraday markets. PICASSO contributes to enhancing the economic and technical efficiency of aFRR exchanges by integrating aFRR markets at the EU level. PICASSO went live successfully in June 2022, before the committed deadline.

Recent literature has also started to quantify the practical implications of European balancing-market integration and the evolution of balancing-market design. In [16] authors estimate sizeable welfare gains from the integration of aFRR activation through PICASSO, showing that cross-border activation can reduce activation-energy use and redistribute benefits across participating countries. In parallel, in [17], authors review recent changes in the European balancing-market design and highlight the growing relevance of shorter products, tighter market timelines, and more dynamic FRR procurement arrangements. At a broader level, [18] argues that balancing in Europe will become more challenging under high shares of variable renewable generation unless market arrangements evolve and cross-border bottlenecks are addressed. These contributions reinforce the relevance of modelling balancing-market coordination jointly with interconnection usage and with the increasing need for flexibility in renewable-dominated power systems.

Studies such as [19], where authors discuss how intermittent renewables affect electricity-generation system operation, and [20], where authors analyse how to manage the operational impact of intermittent generation on power systems, show that the growth of RES in the forthcoming years will greatly impact the system operation, with particular significance in the energy and reserve dispatches. Since reserve requirements depend on multiple factors, the variability that results from higher RES share is challenging the reserve requirements forecasting [21]. Many authors state that the need for short-term reserves is increasing in power systems due to the large amounts of intermittent RES, which asks for more flexible approaches in terms of operation and demand side response [22]. While initially, in countries such as Spain and Portugal – see [23] and [24] –, reserve usage was not increasing with the increment of the installed intermittent RES generation capacity, this has changed in recent years, as shown in Figure 2, built using data in [25] and [26]. Indeed, despite the constant growth of RES installed capacity, aFRR requirements decreased until 2021, but started to grow after 2021, with a lower rate after 2022, possibly thanks to PICASSO going live. Indeed, higher system flexibility availability can be achieved by coordinating reserve procurement among different countries or market zones, increasing competition and liquidity, and reducing costs, allocating the required reserve to supply the demand in real-time, and through the existing interconnections.

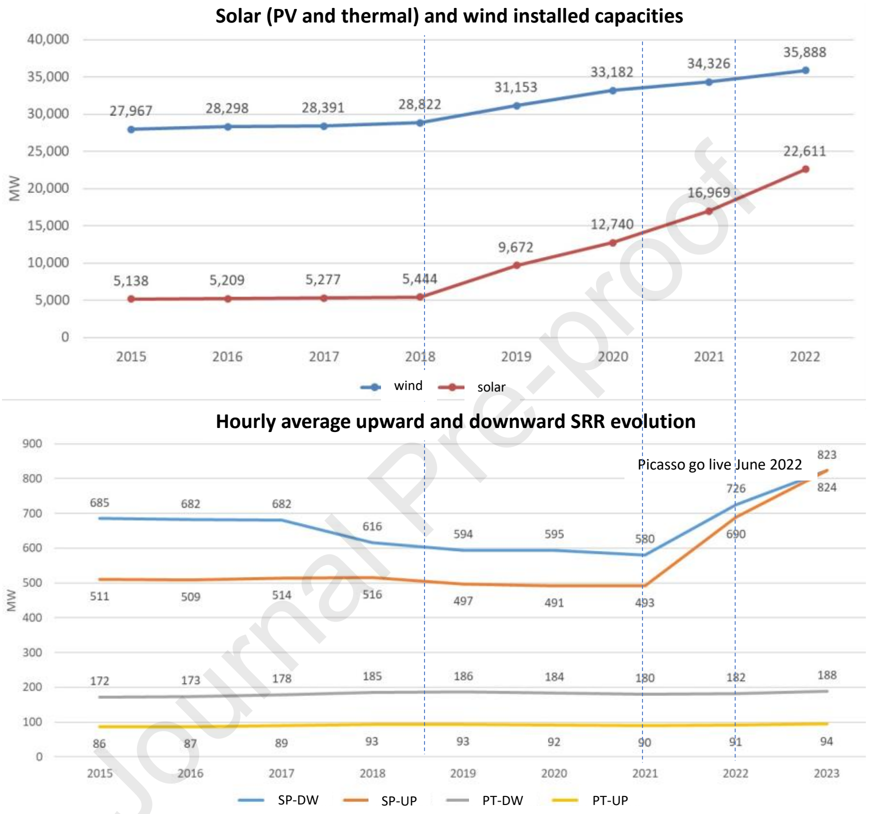

Figure 2 – Spain and Portugal aFRR requirements versus intermittent RES installed capacity.

Coordinating strategic reserves at a multi-zonal level presents many challenges but, when properly implemented, can reduce operating costs and increase the security of supply across Europe. In fact, a joint declaration signed by twelve central European countries reinforce the importance of regional cooperation on this matter [27]. Indeed, a cross-border cooperation can prevent distortions in the wholesale market if a harmonized reserve trigger mechanism is implemented, as suggested in [28]. Without a harmonized trigger, network operators can be tempted to reduce the trigger price for their strategic reserve so that their reserve is used more frequently and their profits increase (which transmission system operators could then use to reduce network fees), which can distort the market competition. Another problem that should be addressed is that Europe has a different portfolio of technologies that can be used in each country’s strategic reserves. Technologies such as coal plants, which are greater carbon emitters, should not be incentivized to supply the strategic reserve among countries. Therefore, a strategy is needed for dispatching some technologies over others. This should be done in a coordinated and fair way, ensuring that technologies are not discriminated against others and that flexible generators are predominantly used in the day-ahead market (see [28]) given the available capacity of the cross-border interconnections.

An issue that comes when coordinating reserves amongst countries is the cost allocation. Cost allocation mechanisms should incentivize countries to setup coordinated cross-border reserves and use the ones with lower cost as a first resource, since this will benefit the system as a whole [28]. This is essential to ensure that countries have a positive contribution to the coordinated strategic reserve.

Coordinated strategic reserves have several benefits [28] such as:

- Availability of reserve generation to meet demand, through a commercial mean, when shortages occur, which is more evident at a cross-border level when transmission capacities allocation is considered.
- Decrease of the overall reserves' costs when considering cross-border coordinated reserves.
- Decrease of the reserve requirements at a national level, since individual demands peaks can occur at different times and be supplied with a cooperation cross-border strategy.

When coordinated strategic reserves take place, cross-border reserve markets increase reliability and the social welfare of the overall internal market. This is why the European Commission (EC) published some guidelines regarding cross-border electricity balancing [29]. However, there are some concerns related with the cross-border interconnection capacity among countries, given the real-time response that is required to activate reserves when needed, as also indicated in [30]. These network constraints should be taken into account when considering a dispatch of cross-border coordinated reserves [31]. At the moment, in the EU, reserves are procured (before real-time) when the system state is uncertain, but they are activated at a real-time pace, with their role gaining significance due to the rising share of RES.

1.1.3 Interconnections Capacity Concepts

At the EU level, in several periods, the lines interconnecting national transmission networks cannot accommodate all physical flows resulting from the international trade requested by market players. Therefore, cross-border congestion management based on efficiently allocating the transmission capacities to minimize the impact on the social welfare is needed, and incentives should be provided by these congestion management mechanisms to promote investments in transmission networks [32]. The allocation of line capacity consists of determining the amounts allocated to the security margin limits, as established in [33], and to the commercial exchanges, by determining the share of the remaining capacity that can be allocated to energy and reserve markets.

Currently, commercial exchanges in Europe are based on two cross-border congestions trade management methods for capacity allocation, market and non-market based [32], as represented in Figure 3.

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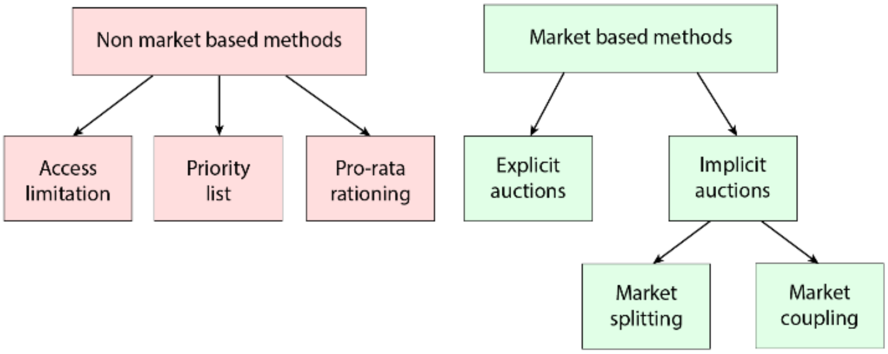

Figure 3 – Non-market based and market-based congestion management methods.

Market-based allocation can be based on explicit capacity auctions, where enough capacity must be bought in capacity markets to accommodate the energy negotiated in the energy markets, or with implicit capacity auctions, where the capacity is implicitly allocated by the market coupling mechanism (see section II.B). Non-market based capacity allocation is usually performed on a day-ahead basis or even solved in real time [32]. For instance, a non-market-based method is the Priority List, on which each market player receives a capacity in priority of order (for example, chronological order or historical use of capacity) until the capacity available for commercial exchanges (ATC, see section II.A.1) is fully allocated. Further details on non-market-based methods can be found in [32] and [34].

In mature electricity markets, congestion management is predominantly carried out through market-based mechanisms, as these are widely preferred to enhance liquidity and transparency relative to non-market-based approaches [32]. The general principles governing congestion management are detailed in Article 16 of Regulation (EU) 2019/943 of the European Parliament [35] and of the Council of 5 June 2019 on the internal market for electricity (recast). According to this provision, network congestion should be resolved through non-discriminatory, market-based solutions that provide efficient economic signals to both market participants and transmission system operators. Nevertheless, some countries continue to rely on non-market-based approaches. For instance, Germany, Austria, and Poland apply cost-based redispatch, while in France and Switzerland redispatch is procured jointly with mFRR and RR [36].

1.1.4 Allocation methods for energy and balancing reserves

The process of defining the maximum volume of allocated cross-zonal capacity for energy and balancing reserves should respect different capacity limitations of the interconnection lines, as defined in the EBGL [37] and explained in [38]. For this, several concepts are defined by ENTSO-E, shown in Figure 4, and computed as follows [39]:

1) The Total Transfer Capacity (TTC) of the interconnection is computed from the lines capacity by considering their physical limits (thermal, voltage and stability limits) that impede the system operation in accordance with the lines security limits, being the maximum physical transmission capacity of the interconnection that can be utilized under ideal and secure conditions.
2) The TTC is then reduced by the Transmission Reliability Margin (TRM) to account for the forecasted uncertainties of power flows. This is done by the TSOs in accordance with past experiences or using statistical methods.
3) Then, the Net Transfer Capacity (NTC), which is the usable transfer capacity after accounting for safety margins, whose use does not lead to the potential violation of network constrains, is computed as: $NTC = TTC - TRM$
4) Using the generation schedules of the selling agents, TSOs perform the load flow calculations corresponding to the allocated cross-border capacity. These planned generation scenarios result in load flows on the interconnections between systems and are called the Notified Transmission Flow (NTF).
5) Finally, the Available Transfer Capacity (ATC), which is the transfer capacity available for market participants usage, is computed as $ATC = NTC - NTF$. Note that, as the allocation process proceeds and new information on these generation schedules becomes available to the TSOs, the load flows are recalculated, and the remaining ATC evaluated for a specific time frame, specified by the commercial activity in analysis (e.g. NTC and ATC are calculated for the day-ahead market trade, and then again for the intraday market considering the result of the day ahead market).

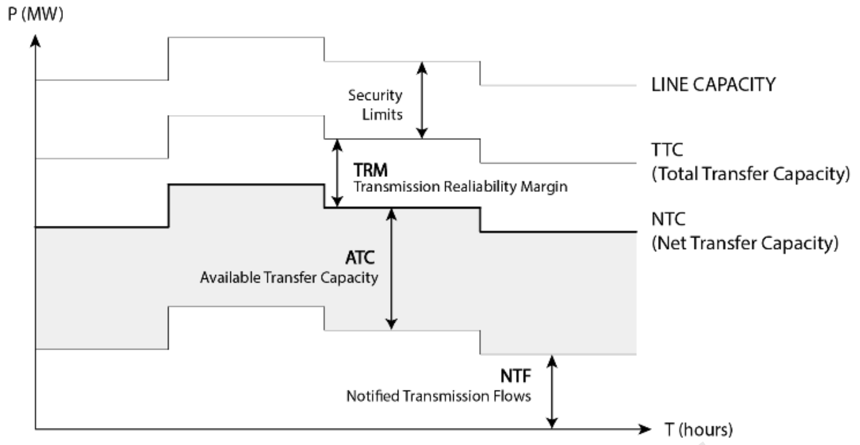

Figure 4 – Summary of NTC and ATC definitions, adapted from [40].

Both NTC and ATC provide a way for TSOs to manage international exchanges and for agents to anticipate and plan their cross-border transactions, as [39] indicates.

For balancing reserves, ENTSO-E discusses three different methods to allocate capacity: *ex-ante* allocations, capacity auctions and counter trading [41].

Ex-ante allocation takes place separately from the existing markets and can exist in different versions. The most common ones are:

- The *ex-ante* allocation based on price assumptions, where the transfer capacity is allocated to different purposes and timeframes based on assumed future prices, typically long-term. For instance, for the valuation of day-ahead exchanges, the prices of forward contracts can be used as price forecasts, combined with an energy market model. For the valuation of reserve exchanges, existing auctions for primary and reserve capacity can be used as a basis for future price estimations.
- The *ex-ante* allocation based on market prices, where the transfer capacity is allocated closer to real-time, with more information available regarding the market. This allocation offers a dynamic solution for a volatile future of both energy and reserve.

Capacity auctions [9], that enable the allocation of the transmission capacity through a market pricing mechanism, are one example of the mechanisms used to guarantee the coordination among EU members. They can be of two types:

- Explicit capacity auctions, with the capacity explicitly allocated in competition with other requests for cross border capacity, granting the market mechanisms absolute control about the determination of the social welfare of the allocation. However, the EC Directorate-General (EC DG) for Competition indicated, in 2007 [2], that explicit auctioning has efficiency deficits when compared to implicit auctioning, especially when intraday and balancing markets have low liquidities.
- Implicit capacity co-optimisation, where cross-border reserve is allocated by TSOs simultaneously with the day-ahead energy trading, with bids for ancillary services in competition with the day-ahead timeframe. The market clearing algorithm, in this case, optimizes the transmission capacity allocation of the interconnections to both energy and reserve. Although more complex to implement, it increases social welfare due to a more efficient allocation.

Finally, the counter trading mechanism frees up transfer capacity for real-time reserve trading. This method allows for fundamental time changes in flows and, therefore, the size of the transfer capacity. It is only possible if suitable markets exist for TSOs to trade in. TSOs can trade counter to the flow on the interconnector, to free up transfer capacity. The prices TSOs pay, and the level of competition are determined by the market conditions. Compared to the other methods, this method involves higher operational risks and, therefore, is not widely used [41].

1.1.5 Market Coupling Mechanism

Among the capacity auction mechanisms described above, the EU market coupling mechanism is used for the EU energy markets cross-border coordination, which is enabled by the TSO of each zone inside ENTSO-E [10]. This mechanism is responsible for harmonizing the EU markets and is already well developed in several European countries, especially for the day-ahead and intraday markets [42].

The EU's market coupling mechanism coordinates electricity markets across member states to optimize cross-border electricity trade. It links most EU day-ahead and intraday markets, allowing energy to flow from regions with lower prices to those with higher prices. Market coupling ensures efficient use of cross-border interconnection capacity by integrating market mechanisms from different countries into a single algorithm called EUPHEMIA [43], which matches supply and demand across borders. This process maximizes social welfare, enhances price convergence, and increases market liquidity while respecting transmission constraints. For this, TSOs communicate the ATC (Available Transfer Capacity) of the cross-border interconnections [44], and MOs, through the power exchanges, manage the trading process. EUPHEMIA market coupling [45] is based on implicit capacity allocation, since market participants do not individually receive allocations of cross-border capacity but bid for the electricity on their power exchange. The market coupling mechanism operates as follows [44]:

1. All TSOs send their cross-border transport capacities to the Market Coupling Operator (MCO).
2. The MCO models centrally and independently the capacity values.
3. TSOs and the MCO validate and monitor the values and exact cross-border capacities permanently.
4. The MCO transmits the capacity values to the electricity exchanges.
5. Electricity traders (market agents) submit their offers.
6. The coupling algorithm clears supply and demand.
7. All players (TSOs, MCOs and electricity traders) check their capacity values once again before publication.

1.2 Review of Market Models Allocating Cross Border Interconnections Capacity

This subsection explores the market modelling methods found that allocate cross-border interconnection capacity, especially in the context of coordinating energy-only or energy and reserve exchanges across multiple bidding zones. It briefly describes such models by outlining their main features and by pointing out some of their limitations. For those models that address interconnections capacity allocation for both energy and reserve, the methodology they follow is also identified.

1.2.1 Market models with cross-border energy exchanges coordination

Several market models can be found representing cross-border interconnections for energy exchanges. For example, EMMA is a north-west European power market model that dispatches power plants and computes new investments by minimizing the total costs related to generation, investments, and trade decisions [46]. It mainly focuses on the wholesale electricity market and on the supply side. Its major limitations are the inelastic representation of the demand, the absence of hydro reservoir modelling, the lack of technical constraints related to the unit commitment of power plants, and the absence of cross-border reserve coordination.

METIS is a model of the European electricity, gas and heat systems at a national and regional levels [47]. It simulates the operation of energy systems and markets hourly over a given year, including uncertainties related to weather variations. It is used by the EC for policymaking and has been designed to address multiple power system problematics with a welfare-maximization principle. It provides productions, production costs, electricity flows, system marginal costs, scarcity periods and loss of load indicators [47]. A major limitation of this model is the fact that the balancing reserve procurement is only made at a national or regional level.

The model proposed in [48] provides a system-wide optimal coordinated energy dispatch method in multi-energy microgrid, both connected to the grid and in island mode. It can be used as a multi-zonal approach for modelling, but lacks the scalability to wider systems, such as the EU Internal Market for electricity.

In [49] a mixed-integer stochastic programming model is proposed for the day-ahead and futures energy markets coordination. This model outputs an optimal biding for the spot market with the optimal allocation of the physical futures contracts among the thermal units.

Recent contributions have further improved the representation of European market coupling and day-ahead clearing. Halužan et al. [50] develop an integrated model for electricity market-coupling simulations and show its usefulness for analysing cross-border market interactions in Europe. Chatzigiannis et al. [51] present a detailed formulation of the European day-ahead electricity market clearing model. These contributions strengthen the modelling of cross-border energy exchanges, but they do not address the simultaneous procurement of balancing reserves or the endogenous allocation of interconnection capacity between energy and reserve services in a long-term chronological framework.

Other works refine the modelling of European day-ahead market coupling itself. In [52] authors propose integrating day-ahead market clearing with preventive redispatch in order to increase efficient cross-border exchanges in the European electricity market, showing that a closer coordination between market clearing and congestion management may improve welfare. In [53], authors develop a decomposition-based approach for pan-European day-ahead electricity market clearing, explicitly motivated by the weak electrical connection between the Iberian Peninsula and the rest of Europe. These contributions strengthen the representation of cross-border energy trading and the computational treatment of European market coupling, but they do not address the simultaneous procurement of balancing reserves or the endogenous allocation of interconnection capacity between energy and reserve services in a long-term chronological framework.

CEVESA, the starting model for this work, is a multi-zonal electricity market model of MIBEL, with is core hourly joint energy-and-reserve formulation described in [54], considering hydro and thermal units, and also modelling interactions between the electricity and the transport sector. In [55], CEVESA was extended with an equilibrium setting for distributed-generation expansion. In [56] CEVESA was used to assess green-hydrogen generation costs, and in [57] it was applied to a joint Portuguese-Spanish NECP analysis.

Previous versions of CEVESA coordinated energy but did not coordinate reserve across the cross-border interconnections. The model developed in this work extends CEVESA to include both commodities coordination.

1.2.2 Market models with cross-border energy and reserve coordination

Some market models have also been found addressing the reserve exchange across multiple zones. For example, the model in [58] enables energy and reserve balancing between countries with cross-border flow coordination, taking the example of Switzerland, Austria and Germany. It has a detailed representation of power plants, scheduled power generation and localized imbalances that lead to reserve balancing capacity needs and to activate balancing energy.

The authors concluded that coordinating procurement and the activation of balancing services among different zones lead to cost reductions. The authors also concluded that capacity reservation positively changes substantially when procuring cross-border coordination, given the more extensive available plant portfolio. However, a major limitation of the model is that the energy flows and capacity allocation are calculated using a two-step approach, instead of being jointly optimized. In the first step, a spot market dispatch determines the energy flows, and only then is the reserve capacity allocated based on those pre-determined cross-border flows.

The analytical model proposed in [59] is a cross-border reserve procurement model that increases supply and dimension efficiencies (reserve capacity needed). However, it only addresses the optimal procurement of reserve capacity and the resulting procurement for both zones, without taking into consideration the market interaction between agents of different zones for reserve. The authors concluded that the reserve exchanges across countries decrease the system costs. They show that cross-border cooperation affects the costs' allocation among TSOs, with some cases of procurement costs increasing, which can harm TSOs cooperation for reserve procurement and can prevent efficiency gains that could exist with the cooperation establishment.

Another model that considers the Northern European power markets is described in [60]. It includes both the day-ahead and the upward and downward aFRR markets. Similar to what happens with the European markets, this model assumes reserve capacity is procured before clearing the day-ahead market and optimizes the transmission capacity based on reserve capacity bids and expected day-ahead prices. The authors assumed that, numerically, there is a cost reduction benefit of cross-border reserve procurement to develop their research. They concluded that there is a cost reduction not only in the aFRR market but also in the day-ahead one, given the fact that procuring reserves in other areas reduces the need of keeping reserves on more "expensive" rotating units, increasing flexibility, and reducing the cost. Therefore, the authors recommend keeping transmission capacity for reserve procurement for both reserve and day-ahead markets.

The authors of [61] note that, at the time of their study, aFRR procurement following spot market clearing – despite its potential benefits – had not yet been implemented in existing systems. This is particularly significant given the necessity of ensuring reserve capacity availability during real-time operation.

Conversely, [62] argues that pre-reserving transmission capacity for FRR exchange offers no advantage, as it becomes suboptimal when compared to a model where spot market clearing is performed simultaneously with the allocation of reserve and transmission capacity.

Studies, such as the one in [63], show that it is possible to achieve a certain level of flexibility, when connecting two different zones, in an efficient and economical way through adequate grid control operations, allowing a link between other control areas to avoid activating different balancing power in-between zones – i.e. avoid activating a reserve to positively correct the supply of demand on one zone and, on the other zone, activating a reserve negatively to balance the power on that second zone. This study also concludes that redesigning the market, instead of commissioning new power to balance the system, has proven to be an efficient solution given the increased flexibility it provides when allocating power in-between zones.

Using a quarter-hourly model for representing in more detail the reserve provision, the authors of [22] indicate that coordinating reserves across different market zones never leads to higher costs than in an uncoordinated scenario. Still, activation costs can increase due to constrains in the transmission system, given that these constraints are generally not considered for coordinating sizing and allocation [22]. This fact can lead to suboptimal market outcomes and can worsen the overall system performance, if not carefully addressed and considered. However, this coordination between market zones also allows lower reserve requirements with smoother forecast errors, reducing costs allocation.

Reference [22] also reports that more research is needed for a coordinated reserve market design that supports the previous framework and grants an appropriate action for each agent. This reality is still in development in Europe since its electricity markets regarding reserve sizing, allocation and activation are still under development in an uncoordinated way across member states, with different heterogenous reserve mechanisms taking place in many countries. Nonetheless, [22] shows that the value for coordination is determined by a trade-off between reducing sizing and allocation costs, and increasing activation costs.

More recent studies also reinforce the relevance of modelling uncertainty and product interdependence in cross-border reserve coordination. Divényi et al. [64] propose an optimization framework for cross-zonal reserve procurement on European power exchanges, highlighting the importance of uncertainty-aware reserve allocation, using the flow-based method. Shi et al. [65] develop a scenario-oriented multi-area joint market-clearing model for energy and reserve under uncertainty, while Van den Bergh and Delarue [66] show that the interdependency between energy and reserve markets becomes stronger as renewable penetration increases. Divényi et al. [67] formulate a European day-ahead clearing algorithm with joint allocation of energy and control reserves, allowing combined energy-reserve orders and market coupling in a single optimization problem. Domínguez et al. [68] compare alternative reserve-procurement timings and degrees of coordination through stochastic scheduling models in renewable-dominated systems, showing that tighter integration between energy and reserve improves efficiency. Gebrekiros et al. [69] analyse reserve procurement and transmission-capacity reservation in the Northern European power market and show that limited transmission reservation for FRR may reduce both reserve-procurement and day-ahead costs. More recently, Ihlemann et al. [70] present a joint day-ahead energy and balancing-capacity clearing model with coordinated procurement, coordinated sizing, and co-optimized cross-zonal transmission allocation for future European systems. Although these studies confirm the value of stronger cross-border coordination, they are primarily focused on short-term and/or uncertainty-oriented market clearing, or on stylized and future European settings. They do not provide a long-term chronological representation, calibrated with real Iberian data, in which energy dispatch, reserve procurement, interconnection-capacity allocation, and explicit unit-commitment operation are determined simultaneously using reserve requirements based on real TSO data.

Moreover, articles that use the flow-based method in their methodology, are not replicable to the Iberian Peninsula case which does not use that method to calculate and allocate capacity. Only NTC allocation methodology, described in [71], is applicable to the Iberian market.

Several models have been used for market modelling, such as [72] that reviews computational game-theoretic models for adaptive urban energy systems and [73] that reviews electricity market modelling trends. These reviews show that cost-minimization and market-equilibrium formulations are among the most widely used approaches for medium- and long-term analysis [74]. In [55], a Nash equilibrium approach to model both centralized and behind-the-meter distributed generation expansion is used. To reduce computational burden, authors use a single representative period instead of modelling a full year. It also includes coordination among single-price areas, but it does not incorporate cross-border reserve coordination, which requires a mathematical reformulation. In [75], authors follows an equilibrium-based approach, but consider a joint energy and reserve equilibrium formulation over an entire year. These two works provide part of the methodological basis for the present research. In this sense, other approaches considering transmission constraints among single-price areas are applied, for example, to the ERCOT System [76], to a multi-zone electricity market [77], to the three-area IEEE-RTS [78] and to the IEEE 118-bus test system [79].

Recent analytical and review-based literature also supports the relevance of modelling energy and reserve jointly. Baldursson et al. [80] derive a competitive equilibrium for coupled spot and reserve markets under uncertain demand and renewable generation, showing that the welfare-optimal reserve volume increases as renewable shares grow. Although this work is not cross-border in scope, it reinforces the theoretical argument that energy and reserve should be analysed as interdependent products, especially in systems with increasing renewable variability. This view is consistent with broader reviews of recent electricity market design. In particular, Silva-Rodriguez et al. [81] identify coordination across energy products and timeframes as a major challenge for short-term wholesale electricity market design, stressing the need for frameworks that can consistently represent the interactions between energy, reserve, and network usage. Together, these contributions further support the use of modelling approaches capable of capturing such coupled decisions when analysing cross-border coordination.

1.2.3 Summary of the literature review on market market models and cross-border coordination mechanisms

Table I summarizes the main market models analysed in the previous sections, by comparing some of their main relevant features, such as energy coordination, reserve coordination, interconnection capacity allocation for energy, interconnection capacity allocation for reserve, hydro dispatch implemented, time resolution, and cross-border coordination: column 2 (Wholesale Electricity Market) refers to whether the model explicitly represents the clearing of the energy market; column 3 (Coordinated Reserves) refers to whether reserve procurement and/or activation is coordinated across zones, rather than being determined independently within each area; column 5 (Energy Capacity Allocation) and column 5 (Reserve Capacity Allocation) refer to whether cross-border interconnection capacity is explicitly allocated to energy exchanges and to reserve exchanges, respectively. Therefore, columns 4 and 5 refer to the product-specific use of transmission capacity. Column 9 (Cross-border coordination) only indicates whether the model represents an explicit multi-zone or multi-country interaction. The remaining dimensions identify whether the model is for operation or investment decisions, whether hydro management is represented, and time resolution.

Table I. Comparison Between Models.

Ref.	Wholesale Electricity Market	Coordinated Reserves	Energy Capacity Allocation	Reserve Capacity Allocation	Operation (O) or Investments (I)	Hydro Management	Hourly Model	Cross-border coordination
[22]		X		X	O		Quarter-hourly time resolution	X
[46]	X	X			Both		X	
[47]	X	X			Both	X	X	
[48]	X				O		X	
[49]			X		O			
[59]		X		X	O			X
[60]	X	X	X	X	O	X	X	X
[61]		X			O		X	X
[62]	X	X	X	X	O	X	X	X
[63]	X	X		X	O			X
[50]	X		X		O		X	X

[51]	X		X		O		X	X
[64]	X	X	X	X	O		X	X
[65]	X	X	X	X	O			X
[66]	X		X		O		Quarter-hourly time resolution	X
[67]	X	X	X	X	O		X	X
[68]	X	X	X		O		X	X
[69]	X	X	X	X	O	X	X	X
[52]	X		X		O			X
[53]	X		X		O		X	X
[70]	X	X	X	X	O		Quarter-hourly time resolution	X
CEVESA ([54], [55], [56], [57])	X		X	(Goal of this research)	Both	X	X	(Goal of this research)

Table I allows to conclude that although several models represent relevant parts of the problem, such as wholesale electricity market clearing, reserve coordination, hydro management, or cross-border exchanges, only a limited number of them model these all these features simultaneously. Indeed, most reviewed models either focus only on energy coordination, or include reserve coordination without jointly representing the endogenous allocation of interconnection capacity between energy and reserve services in a long-term chronological framework. Only the model proposed in this paper, as an extension of CEVESA market model, combines hourly market operation, hydro management, multi-zonal cross-border interaction, and the simultaneous treatment of energy and reserve exchanges within a single modelling framework. This makes it especially suitable for assessing the trade-offs associated with scarce interconnection capacity in realistic Iberian market conditions.

By focusing on those models from Table I that provide both energy and reserve capacity allocation, Table II summarizes how these models address cross-border coordination of energy and reserve. Identified approaches are predominantly based on sequential or otherwise decoupled formulations, where interconnection capacity is allocated either exogenously or in multiple stages.

Table II. Detailed comparison of cross-border energy and reserve market models.

Ref.	**Solution approach (SEQUENTIAL VS SIMULTANEOUS)**	**Temporal resolution**	**Network representation DETAIL**	**Treatment of uncertainty**	**Computational scope / complexity**

[22]	Sequential (probabilistic sizing → deterministic allocation → real-time activation)	Quarter-hourly	Zonal ATC-based network; interzonal constraints only	Explicit wind and solar forecast uncertainty	Very high (multi-stage unit commitment simulations)
[59]	Sequential (reserve procurement analysed independently of energy dispatch)	Static (contracting period)	Multi-zone copperplate with exogenous interzonal limits	Explicit probabilistic modelling of reserve needs	Moderate (analytical + numerical evaluation)
[60]	Sequential (reserve capacity allocated prior to or separately from energy dispatch)	Hourly	Zonal network with NTC-based interconnection constraints	Deterministic; uncertainty embedded in reserve requirements	High (large-scale)
[61]	Sequential (balancing activation optimized given exogenous imbalances and capacities)	Representative imbalance cases (no chronology)	Multi-zone zonal model with fixed interconnection capacities	Scenario-based (probabilistic imbalance cases)	Moderate (LP-based optimization over scenarios)
[62]	Sequential (day-ahead dispatch → reserve procurement → real-time balancing)	Hourly (day-ahead and balancing stages)	Zonal NTC-based network with reserved vs. residual capacity	Deterministic imbalances; uncertainty implicit via historical inputs	High (multi-stage market simulation)
[63]	Not applicable (empirical, non-optimization analysis)	Hourly or weekly	Zonal aggregation; no explicit network constraints	Implicit (historical variability only)	Low/moderate (statistical analysis)
[64]	Simultaneous (joint co-allocation of energy and reserve in one clearing MILP)	Hourly (short-term)	Flow-based multi-zonal network using PTDFs/CBCOs; the demonstration case keeps cross-zonal lines only **(not applicable to MIBEL)**	Robust optimization / worst-case reserve-deployment flows	Moderate/high (MILP; demonstrated on 5 zones over 7 simulated days, with larger-scale tests aimed at practical bid volumes)
[65]	Simultaneous (multi-area joint clearing / co-optimization of energy and reserve with interface bids)	Scenario-based nominal state plus non-base scenarios; no explicit hourly chronology	Multi-area network with internal lines, tie-lines, and boundary-bus interface bids; validated on a 3-area split of the IEEE 118-bus system **(not applicable to MIBEL)**	Scenario-based uncertainty with probabilities for outages and load/renewable forecast errors	Moderate/high (validated on a 2-area toy case and an IEEE 118-bus, 3-area case)
[67]	Simultaneous (joint day-ahead clearing of energy and control reserves in one optimization problem)	Hourly (day-ahead/short-term)	Coupled bidding zones with market coupling and cross-zonal capacity limits; no detailed internal grid representation;	Deterministic	Moderate (convex MIQP with European bid types and non-convex orders) **(numeric simulation only; lacks realistic full-year hourly**

			(bid design only, no unit commitment)		**chronological operation)**
[68]	Sequential and simultaneous benchmark formulations (three stochastic scheduling models comparing reserve-procurement timing and coordination)	Hourly (day-ahead) + Real-time stochastic scheduling (short-term)	Stylized zonal network with cross-border constraints inspired by European reserve-procurement designs	Explicit renewable uncertainty via stochastic programming	Moderate/high
[69]	Sequential (FRR bid-pricing block → reserve procurement with transmission reservation → day-ahead dispatch)	Hourly (day-ahead)	Zonal Northern European system with reserved cross-border transmission capacity	Deterministic; bidding based on spot-price forecasts	Moderate/high
[70]	Simultaneous (joint day-ahead energy and balancing-capacity clearing with coordinated procurement, sizing, and transmission allocation)	Quarter-hourly (**short-term**/day-ahead)	Cross-zonal European model with co-optimized transmission capacity between zones (**clustered based unit commitment**)	Deterministic	High (clustered MILP/UC; high-renewables CWE case study only)
CEVESA extension (proposed model)	**Simultaneous** (joint co-optimization of energy, reserves, and interconnection capacity)	Hourly (**long-term**, **full-year chronological simulation**)	Multi-zone zonal network with shared NTC constraints for energy and reserves **(unit commitment detail)**	Deterministic (historical foresight; exogenous reserve needs)	High (large-scale over 8760 h with unit commitment)

As can be seen, Table II shows that most existing cross-border energy and reserve models rely on sequential or partially decoupled solution structures, short-term scheduling horizons, stylized case studies, or more detailed network formulations that are not directly applicable to the Iberian NTC-based setting.

By contrast, the proposed CEVESA extension simultaneously determines energy dispatch, reserve procurement, and cross-border capacity allocation within a unified optimization problem. This allows to model the opportunity cost of allocating scarce transmission capacity between energy and reserve services to be endogenously captured, which cannot be achieved with sequential approaches. CEVESA extension adopts a simultaneous co-optimization framework in which energy dispatch, reserve procurement, and interconnection-capacity allocation are determined jointly over a full-year hourly horizon with unit-commitment detail. This allows the model to capture the opportunity cost of allocating transmission capacity between competing services in a way that sequential approaches cannot, while remaining consistent with the zonal and NTC-based representation used in the Iberian market. Therefore, Table II highlights that the novelty of the paper is not only the co-optimization itself, but also its implementation in a realistic, long-term, and operationally detailed framework calibrated to the full Iberian system.

1.3 Contributions

Taken together, the regulatory background and the literature review point to the same unresolved issue: the lack of a long-term chronological market model, calibrated to real Iberian data, that simultaneously determines energy dispatch, reserve procurement, and the allocation of scarce interconnection capacity between both services. This gap is particularly relevant in the Iberian context, where cross-border capacity is currently handled through NTC-based mechanisms rather than flow-based capacity calculation. For this reason, the present work focuses on an NTC representation, which is the framework effectively applicable to MIBEL at present, whereas flow-based formulations are not considered here because they are not the operative approach for the Iberian border [71]. Based on this gap, the hypothesis of this paper is that simultaneous co-optimization of cross-border capacity for energy and aFRR reduces total system cost and reserve price separation more effectively than energy-only coordination. To test this hypothesis, the paper extends the CEVESA market model with a unified formulation for joint energy and reserve interconnection-capacity allocation and applies it to a realistic Iberian case study.

A key distinguishing feature of the proposed approach is its simultaneous co-optimization of cross-border interconnection capacity for energy and reserve services, as opposed to the sequential allocation models commonly adopted in the literature. By contrast, the unified formulation proposed in this paper jointly determines energy dispatch, reserve procurement, and interconnection capacity allocation within a single optimization problem, which is aligned with Article 41 of the EBGL [37]. This enables the model to internalize the opportunity cost of allocating capacity to one service over the other, resulting in a more efficient use of cross-border transmission and improved system-wide cost minimization. In sequential approaches such as those proposed by Lorenz and Gerbaulet in [58] and by Gebrekiros and Doorman in [60], interconnection capacity is first allocated based on the outcome of the day-ahead energy market, and only subsequently reserve provision is addressed using the remaining available capacity. While computationally convenient, this two-step structure implicitly assumes that energy and reserve decisions are not coupled. In practice, however, both services compete for the same limited interconnection resources, and allocating capacity sequentially can lead to suboptimal outcomes by failing to capture the trade-offs between cross-border energy exchanges and reserve capacity availability.

Building on this motivation, the main contributions of this paper are as follows:

- A comprehensive literature review on interconnection capacity allocation for electricity and reserve services in the EU, with a focus on generation and automatic Frequency Restoration Reserves (aFRR). This review provides a clear reference on coordination mechanisms, including how Transmission System Operators (TSOs) allocate interconnection capacity for both security margins and commercial exchanges of energy and reserves.
- A review of market models addressing energy and reserve coordination both within and between single-price areas. Special attention is given to the CEVESA market model, developed by the authors' institutions, which has been used to analyze hydrothermal coordination in energy and reserve [54], decentralized generation investments [55], power prices impact on green hydrogen generation [56], and a joint analysis on the Spanish and Portuguese National Energy Climate Plans (NPECs) [57]. A previous version of this model, prior to this work, co-optimizes energy and aFRR within single-price areas, allocating cross-border interconnection capacity only for energy.
- Development and integration of a novel model for the joint allocation of interconnection capacities to energy and reserve within the CEVESA framework. This extension enhances CEVESA's capability, enabling co-optimization of cross-border exchanges and improving the representation of multi-service coordination in coupled electricity markets.
- Application of the enhanced model to a realistic Iberian case study, assessing the economic and operational impacts of different coordination strategies for interconnection capacity allocation. The study evaluates how

capacity levels influence efficiency, reserve price volatility, and cross-border flexibility under various integration scenarios.

The rest of the paper is organized as follows. Section 2 presents the proposed model for the joint clearing of energy and reserve and for the optimal allocation of cross-border interconnection capacity among EU zones. Section 3 applies the model to a realistic case study and discusses the corresponding results. Finally, Section 4 summarizes the main conclusions of the work and outlines directions for future research.

2. Proposed Model for Cross-Border Interconnections Capacity Allocation

This section proposes a cross-border interconnection capacity allocation model integrated into the CEVESA market model, aimed at jointly optimizing the allocation of transmission capacity for energy and reserve commodities within a unified formulation. The objective is to enhance previous CEVESA's representation of market coupling by simultaneously modelling energy exchanges and reserve capacity coordination mechanisms, such as PICASSO. Only aFRR is considered, as its capacity reservation directly affects energy dispatch through the commitment of regulating capacity, while other balancing products (mFRR and RR) are not modelled. Importantly, the proposed formulation is not a purely conceptual construction but an extension of the already calibrated and validated CEVESA model, which has been applied in multiple studies to reproduce observed Iberian market outcomes using real system data, including the hybridization of the CEVESA MIBEL market model based on market outcomes in [82], its subsequent improvement using real market data in [83], the analysis of the Portuguese and Spanish NECPs in [84], the extension of that analysis to the updated NECPs in [85], and the study of NECP-based wind and solar deployment scenarios in Portugal in [86]. Building on this already established market model significantly lowers the barrier to practical adoption, enabling realistic and relevant assessments of joint energy and reserve coordination without requiring extensive redevelopment. Indeed, this model is currently being used to support the elaboration of the Portuguese National Storage Strategy of the Portuguese government, where interconnections with Spain play a determinant role.

The proposed formulation adopts a centralized system cost minimization perspective and, therefore, does not explicitly model strategic behaviour of market participants. In real electricity markets, particularly in systems with concentrated generation portfolios or limited liquidity, cross-border coordination could in principle create opportunities for market power exercise, such as strategic withholding of energy or reserve capacity in one zone to influence prices. Nevertheless, this cost-minimization modelling strategy is consistent with the current European design for aFRR markets, where reserve procurement, cross-border capacity allocation, and activation are largely coordinated by TSOs through regulated platforms (e.g., PICASSO). CEVESA already includes an optional Nash equilibrium based execution mode for energy-market simulations, and analogous formulations for joint energy and reserve settings are consistent with established modelling trends [87]. However, estimating/calibrating conjectural variations is difficult and can be highly uncertain [88], particularly for long-term assessments.

Figure 5 illustrates the overall model architecture, detailing the inputs, scenario definition, and outputs employed in Section 3, along with the CEVESA market-clearing process and the corresponding equations and constraints developed in this section.

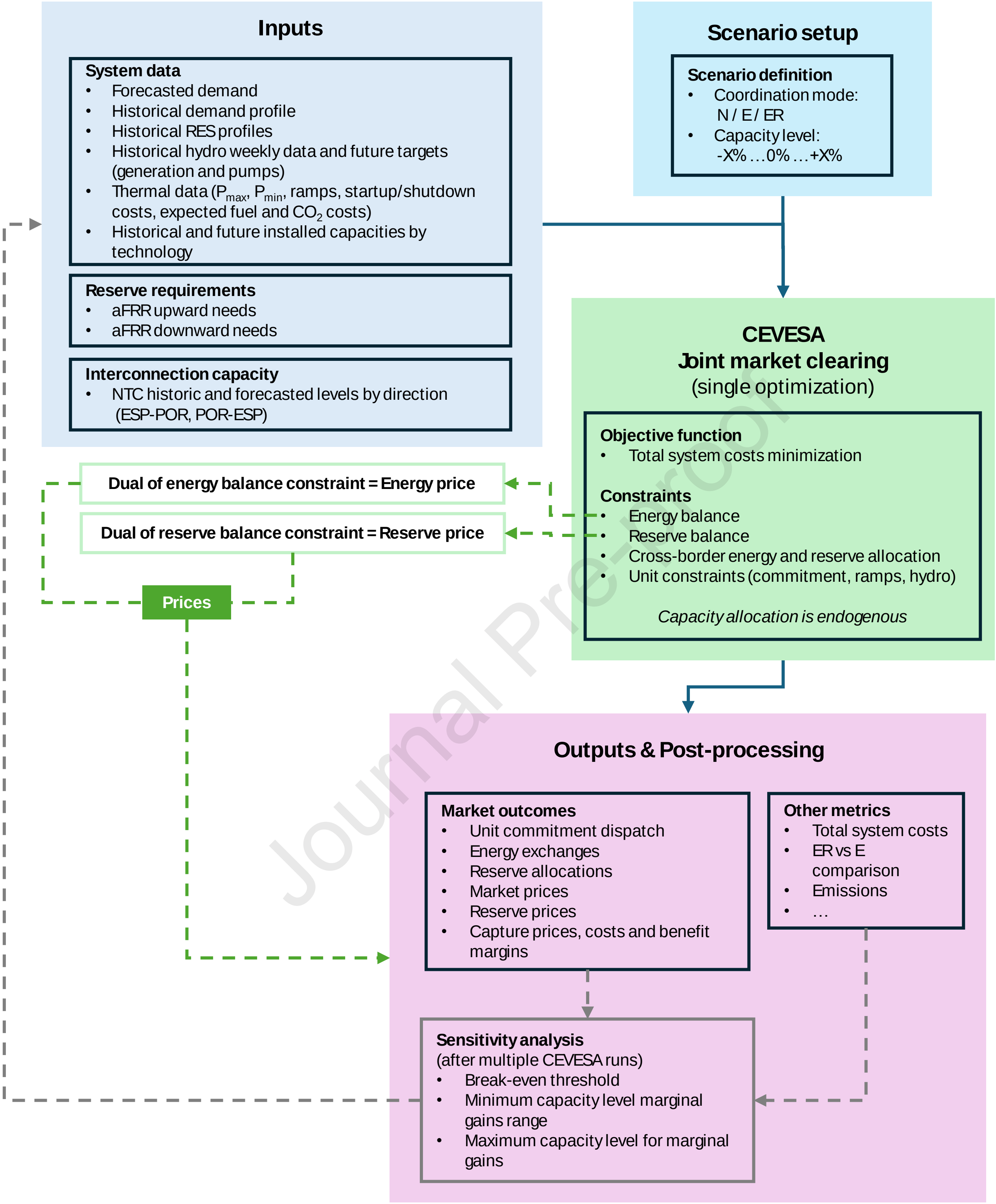

Figure 5 – Flowchart of Model Architecture.

2.1 Model assumptions

The modelling approach presented in this paper relies on the following assumptions:

- The model follows a deterministic optimization method and assumes perfect foresight of relevant system variables, among others, renewable energy availability, electricity demand, and fuel and CO2 prices. As it is common in this type of models, these inputs are derived from historical data and projected to the future with a different combination of qualitative and quantitative approaches [86]. This approach helps to establish the baseline for evaluating coordination strategies under controlled conditions. It partially accounting for uncertainties with large simulation horizons (such as yearly ones) due to the large variability of situations represented. Similarly, reserve requirements are treated as fixed inputs, taken directly from historical records released by the Iberian TSOs. As was shown in Figure 2, reserve requirements are increasing.
- NTC constraints between market zones have been considered. This approach aligns with current European market coupling practices and is commonly used in broader market-level analyses, where NTC are derived by TSO from detailed grid constraints analysis. As such, NTC are a simplified way for TSOs to provide the available interconnection capacities to market operators for market coupling. In the specific case of the Iberian Peninsula, interconnection capacity with France is still relatively limited, so the system often behaves close to an electrical island, making a two-zone representation a reasonable approximation for market-level dynamics.

2.2 Objective function

In its simplest version (centralized dispatch without investment decisions and transmission sector interactions), CEVESA main objective function, equation (1), corresponds to minimize the system costs (or equivalently to maximize the social welfare since demand is considered inelastic), including start-up, shutdown, and variable costs (including CO_2 allowances emissions costs) of each thermal generation unit.

$$FO = \sum_{u \in T,h} \left(C_u^V \cdot q_{u,h} + C_u^{ON} \cdot y_{u,h} + C_u^{OFF} \cdot z_{u,h} \right) \tag{1}$$

2.3 Balancing constraints

Equation (2) guarantees that the total generation matches the electricity demand $D_{z,h}$, which has been assumed to be inelastic.

$$Q_{z,h}^{PRED} + \sum_{u \in U_z} q_{u,h} + \sum_{l \in L_z^{TO}} e_{l,h} = D_{z,h} + \sum_{l \in L_z^{FROM}} e_{l,h} : \lambda_{z,h}^{e} \tag{2}$$

Note that the dual variable of this equation is the energy marginal cost $\lambda_{z,h}^{e}$ of the energy market.

2.4 System reserve constraints

The procedure for the hourly allocation of the NTC (capacity available for commercial exchanges) to energy and reserve is based on the maximization of the social welfare, with implicit capacity auctions of both energy and reserve, as shown in Figure 6. As can be seen, as the capacity allocated to reserve increases, the marginal value of the capacity allocated for energy decreases, and the marginal value of the capacity allocated to reserve increases. The optimal allocation corresponds to the two marginal curves intersect.

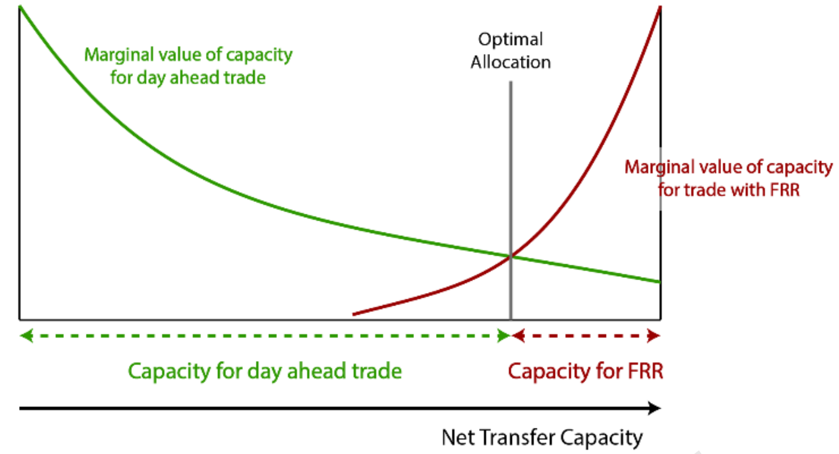

Figure 6 – Optimal capacity allocation between two zones [41].

The following constraints are used to model CEVESA aFRR capacity reserves:

$$\sum_{u\in(T\cup H)\cap U_z} ur_{u,h} + \sum_{l\in L_z^{TO}} ur_{l,h} = ur_{z,h}^{need} + \sum_{l\in L_z^{FROM}} ur_{l,h} \tag{3}$$

$$\sum_{u\in(T\cup H)\cap U_z} dr_{u,h} + \sum_{l\in L_z^{TO}} dr_{l,h} = dr_{z,h}^{need} + \sum_{l\in L_z^{FROM}} dr_{l,h} \tag{4}$$

$$ur_{z,h}^{need} = UR_{z,h}\colon \lambda_{z,h}^{r} \tag{5}$$

$$ur_{z,h}^{need} = \frac{UR_{z,h}}{DR_{z,h}} \cdot dr_{z,h}^{need} \tag{6}$$

Equations (3) and (4) guarantee that the upwards and downwards capacity reserve needs ($ur_{z,h}^{need}$ and $dr_{z,h}^{need}$) in a given zone z plus the reserve that leaves that zone ($\sum_{l\in L_z^{FROM}} ur_{l,h}$ or $\sum_{l\in L_z^{FROM}} dr_{l,h}$) are met with the reserve provided by the generation units of zone z $plus$ the reserve that comes to that zone ($\sum_{l\in L_z^{TO}} ur_{l,h}$ or $\sum_{l\in L_z^{TO}} dr_{l,h}$). For simplicity, only thermal units (excluding nuclear units) and hydro units are considered to provide aFRR.

Equation (5) establishes that the total upwards reserve $ur_{z,h}^{need}$ must match the published needs $UR_{z,h}$ for each zone, being the dual variable of this equation the marginal cost λ_h^r of the aFRR capacity reservation market.

Equation (6) sets that the ratio between the up and down reserves ($ur_{z,h}^{need}$ and $dr_{z,h}^{need}$) must be the same as the ratio between the up and down needs $UR_{z,h}$ and $DR_{z,h}$, which is a common requirement of TSOs, although current changes are ongoing [89]. For example, in Portugal this ratio is $\frac{UR_{z,h}}{DR_{z,h}} = 2$ [90], while in Spain it changes on an hourly basis.

Using the NTC concept, the electricity that flows in each line l on an hourly basis is constrained as follows (note that $e_{l,h}, ur_{l,h}$ and $dr_{l,h}$ are free variables, otherwise constraints would lead to a contradiction):

$$-NTC_{l,h}^{FROM} \leq e_{l,h} \leq NTC_{l,h}^{TO} \tag{7}$$

$$e_{l,h} + ur_{l,h} \leq NTC_{l,h}^{TO} \tag{8}$$

$$e_{l,h} + ur_{l,h} \leq -NTC_{l,h}^{FROM} \tag{9}$$

$$e_{l,h} - dr_{l,h} \leq NTC_{l,h}^{TO} \tag{10}$$

$$e_{l,h} - dr_{l,h} \leq -NTC_{l,h}^{FROM} \tag{11}$$

Equation (7) guarantees that energy flow is constrained to the NTC in the corresponding direction. Equations (8) and (9) guarantee that the flow that could result from the energy and the up reserve from one zone to the other do not surpass the lower limit set by NTC in the corresponding direction.

Similarly, equations (10) and (11) guarantee that the flow that could results from the energy and the down reserve from one zone to the other do not surpass the limit set by NTC in the corresponding direction.

2.5 Thermal units' technical constraints ($\boldsymbol{u} \in \boldsymbol{T}$)

Thermal units operation is constrained as follows:

$$q_{u,h} = u_{u,h} \cdot P_u^{MIN} + \ qp_{u,h} \tag{12}$$

$$qp_{u,h} \leq u_{u,h} \cdot (P_u^{INS} - P_u^{MIN}) \tag{13}$$

$$q_{u,h} + ur_{u,h} \leq \ u_{u,h} \cdot \ P_u^{INS} \tag{14}$$

$$dr_{u,h} \leq q_{u,h} - u_{u,h} \cdot P_u^{MIN} \tag{15}$$

Equation (12) sets that the active power $q_{u,h}$ of thermal unit *u* is above its technical minimum P_u^{MIN}, with $qp_{u,h}$ being the active power above that technical minimum.

Constraint (13) imposes the upper bound to $qp_{u,h}$, which is determined by the difference between the installed capacity P_u^{INS} and the technical minimum P_u^{MIN}.

Constraint (14) relates the active power $q_{u,h}$ and the upper reserve $ur_{u,h}$ with the unit's run decision $u_{u,h}$ and its installed capacity P_u^{INS}.

Finally, constraint (15) defines the physical limit of the down reserve as the difference between the power $q_{u,h}$ and the technical minimum P_u^{MIN}.

CEVESA guarantees the ramps of each thermal unit considering the worst-case scenario for reserves (as also assumed in [54], [55]):

$$\left(qp_{u,h} + ur_{u,h}\right) - \left(qp_{u,h-1} - dr_{u,h-1}\right) \leq u_{u,h} \cdot \ URG_u \tag{16}$$

$$\left(qp_{u,h-1} + ur_{u,h-1}\right) - \left(qp_{u,h} - ur_{u,h}\right) \leq u_{u,h} \cdot \ DRG_u \tag{17}$$

Equation (16) enforces that the power plus the up reserve of a thermal unit *u* for a given hour h minus the power minus the down reserve at the previous hour h-1 do not surpass the maximum ramp URG_u for each unit u. Likewise, equation (17) guarantees the down ramp is below the maximum down ramp DRG_u.

Equations (18) and (19) limit the up and down reserves a unit u can provide considering its ramp and response time TR requested to provide the reserve in the TSOs operational procedures [91].

$$ur_{u,h} \leq URG_u \cdot TR \cdot u_{u,h} \tag{18}$$

$$dr_{u,h} \leq DRG_u \cdot TR \cdot u_{u,h} \tag{19}$$

where TR represents the maximum regulated activation time for the aFRR service, set to 5 min as defined in most EU TSO operation procedures or in PICASSO [92].

Equation (20) sets the logic between the start-up, shut down and coupling decisions.

$$u_{u,h} - u_{u,h-1} = y_{u,h} - z_{u,h} \tag{20}$$

2.6 Hydro units' technical constraints ($\boldsymbol{u \in M}$)

Equations (21) to (27) define the constraints for both energy and reserve supply for each hydro unit. Details on the hydro modelling can be found on [54].

$$\sum_{u \in M, h \in H_w} q_{u,h} \leq Q^{E}_{M,w} \tag{21}$$

$$\sum_{h \in H_w} q_{u,h} \leq Q^{E}_{u,w} \tag{22}$$

$$\sum_{h \in H_w} bh_{u,h} = EF_u \cdot \sum_{h \in H_w} q_{u,h} \tag{23}$$

$$q_{u,h} + ur_{u,h} \leq Q^{MAX}_{u,w}, h \in H_w \tag{24}$$

$$q_{u,h} - dr_{u,h} \geq Q^{MIN}_{u,w}, h \in H_w \tag{25}$$

$$\sum_{h \in H_w} ur_{u,h} \leq Q^{UR}_{u,w} \tag{26}$$

$$\sum_{h \in H_w} dr_{u,h} \leq Q^{DR}_{u,w} \tag{27}$$

Constraint (21) imposes the maximum weekly hydro generation $Q^{E}_{m,w}$, which is estimated based on historical data [54], while (22) the maximum weekly hydro generation $Q^{E}_{u,w}$.

Equation (23) relates the weekly pumped energy to the weekly generated energy of each unit considering the efficiency factor.

Constraints (24) and (25) limit both the energy generation and the reserve allocation for each unit, where limits $Q^{MAX}_{u,w}$ and $Q^{MIN}_{u,w}$ are the maximum and minimum weekly historical thresholds. Constraints (26) and (27) limit the upper and down reserve allocation for each unit with historical weekly thresholds $Q^{UR}_{u,w}$ and $Q^{DR}_{u,w}$ (see [54] for more details).

2.7 Renewable generation technical constraints ($\boldsymbol{u} \in \boldsymbol{R}$)

RES generation is based on historical generation hourly profiles $Q_{u,h}^{R}$, and equation (28) links the input profile with the effective generation and the curtailment that may be needed when all the RES that cannot be harnessed in the system:

$$q_{u,h} = Q_{u,h}^{R} - s_{u,h} \tag{28}$$

3. Case Study

This section presents the results of a comprehensive case study designed to evaluate CEVESA's performance including the proposed cross-border interconnection capacity formulation modelled by constraints (7) to (11). The analysis is based on full-year hourly simulations covering all 8760 hours of year 2023 operation and it uses real system data for demand, generation, reserve requirements, and interconnection capacities. To assess the effects of different energy and reserve coordination strategies, a range of scenarios is considered with varying increasing and decreasing amounts of interconnection capacity. This setup is used to validate the robustness of the results across all diverse operating conditions and system stress levels that can take place during a whole year, rather than relying on selected representative days.

The case study represents the Iberian power system (made of Spain and Portugal) as two single price areas interconnected with a virtual line. Since the Iberian power system behaves almost as an electrical island regarding the rest of Europe, the influence of interconnections with other countries was neglected. Without loss of generality, scenarios are based on 2023 data, with CEVESA model calibrated and validated as described in [82].

To parameterize the unit-level reserve ramping limits in the case study, the response-time parameter, TR, is applied in equations (18) and (19) to translate each unit's ramp limits into the maximum upward and downward aFRR capacity deliverable within the activation window. Since CCGT units typically provide aFRR ramps that are usually several times (1.5 to 4) larger than normal ramps (fast-ramping gas turbines in [93]; CCGT flexibility improvements in [94]; ramp-rate enhancement through compressed-air injection in [95]), TR was set to 3·5 min=15 min=0.25 h.

3.1 Data sources

The monthly NTC values, which reflect the cross-border capacity available for commercial transactions between countries, were downloaded from the ENTSO-E Transparency Platform [96].

The reserve requirements for Portugal were gathered from the Portuguese TSO (REN) platform SIMEE [97], and for Spain from the Spanish TSO's (REE) platform ESIOS [23].

Other technical data used as model inputs were downloaded from different sources. For example, hydro and thermal units' data were downloaded from OMIE [98], with thermal technical data downloaded from JCR Open Database [99]. Hydro generation and non-dispatchable technologies (such as solar and wind) data were downloaded from SIMEE [25] and ESIOS [26]. Fuel (TTF and API2) and CO_2 prices were gathered from Aleasoft reports [100]. Hydro generation is dispatched based on historical weekly data as described in [54].

3.2 Scenarios definition

For the simulations we considered several scenarios: no cross-border coordination (N), energy only coordination (E), and energy and reserve coordination (ER). We also considered several values of NTC capacities (ER-H and ER-L). All scenarios include energy and aFRR capacity dispatches but with different coordination options, as described in

TABLE III. The first letters of the scenario code define the coordination type, N standing for no coordination, E for energy only coordination, and ER for energy and reserve coordination. Note that no energy coordination means that each zone must supply its demand with its own generation considering no exchanges among zones, and similarly, no reserve coordination means that each zone must provide its own reserve without support from and to other zones. Different interconnection capacities were also tested, with letter H referring to higher capacity than in the base scenario (without H and L), and L to lower capacity than in the base scenario.

Table III. Scenarios' Description

Code	**Name**	**Description**
N	No coordination	Interconnections are not used (island mode)
E	Energy only coordination	Energy-only exchange
ER	Energy and Reserve coordination	Energy and reserve exchange
ER-H	Energy and Reserve coordination with Higher NTC	Energy and reserve coordination, considering an increase of 25% of interconnection capacity
ER-L	Energy and Reserve coordination with Lower NTC	Energy and reserve coordination, considering a decrease of 25% of interconnection capacity

3.3 Results analysis

TABLE IV compares the total costs obtained for all the simulated scenarios. Note that the cost reduction of scenario E is obtained regarding to scenario N (no coordination at all), while the cost reduction of ER scenarios (that include reserve coordination) is obtained regarding scenario E (with energy coordination).

Table IV. Scenarios' total cost comparison.

Scenario	**Total Cost (M€)**	**Reduction compared to E (M€)**	**Reduction compared to E (%)**
N	7,209.06	-	-
E	6,770.45	438.61 (cf. N)	6.08% (cf. N)
ER	6,766.23	4.22 (cf. E)	0.06% (cf. E)
ER-H	6,757.22	13.23 (cf. E)	0.20% (cf. E)
ER-L	6,799.64	- 29.19 (cf. E)	- 0.43% (cf. E)
E-H	6,761.56	8.89 (cf. E)	0.13% (cf. E)
E-L	6,805.20	- 34.75 (cf. E)	- 0.51% (cf. E)

The results reported in Table IV show that:

- There is a reduction of 6.08% in the total system costs (considering both Spain and Portugal) when energy coordination is implemented, consistent with current literature (e.g., [101]).
- As expected, coordinating reserves leads to an additional decrease in the total costs compared to the energy-only coordination scenario, although less significant. This is also coherent with the limited significance of the cost of

the aFRR reserve in the total cost, as can be checked in [102] for the Spanish system, of about 2.64 €/MWh of the total 100.18 €/MWh (2.6%). However, although the percentage reduction of the total cost in scenario ER is less than 0.1%, this translates into savings of millions of euros by the end of the year.

- Finally, increasing or decreasing the available capacity (scenarios ER-H or ER-L) amplifies the ER coordination effects: lower capacity leads to lower coordination benefits and vice versa.

Table V shows the annual average market price, average reserve price, energy cost and reserve cost (annual average weighted prices) for the simulated scenarios. The annual average energy and reserve costs (columns 4 and 5 of TABLE V) were calculated using equations (29) and (30), respectively. For instance, (29) averages the market price by the generated energy in each period and (30) averages the reserve price by the allocated upward and downward volumes.

$$\rho^e = \frac{\sum_{u,h} \lambda_h^e \cdot q_{u,h}}{\sum_{u,h} q_{u,h}} \tag{29}$$

$$\rho^r = \frac{\sum_{u,h} \lambda_h^r \cdot \left(ur_{u,h} + dr_{u,h}\right)}{\sum_{u,h}\left(ur_{u,h} + dr_{u,h}\right)} \tag{30}$$

Table V. Annual average market price, Annual average energy cost and Annual average reserve cost.

Scenario	**Annual average market price (€/MWh)**	**Annual average reserve price (€/MW)**	**Annual average energy cost (€/MWh)**	**Annual average reserve cost (€/MW)**
N	113.82	45.28	96.97	53.53
E	98.52	39.56	98.14	43.66
ER	97.95	40.34	97.58	46.25
ER-H	97.42	39.77	97.78	46.08
ER-L	101.10	34.48	98.60	39.86

When looking at the individual average commodities costs in Table V:

- Interestingly, the lack of coordination of scenario N (island mode) has the lowest energy cost but the highest reserve cost when compared to the other scenarios.
- Allowing energy exchanges as in scenario E increases the energy cost but decreases the reserve costs, and also leads to a lower total system cost as TABLE IV showed, given the fact that it allows a joint dispatch between the two zones which increases the overall system efficiency.
- The coordination of both energy and reserve between zones of scenario ER shows that the energy cost decreases (although very slightly) due to a better usage of the capacity available for energy exchanges, which is compensated by the increase in the reserve cost, but again leading to a lower total system cost (as was seen TABLE V) due to the increased system efficiency coming from the increased system flexibility of a more efficient unit dispatch to meet both energy and reserve requirements.
- Again, increasing or decreasing the available NTC capacity (scenarios ER-H or ER-L) amplifies the ER coordination effects: lower capacity leads to lower coordination benefits and vice versa.

Figure 7 shows the average market prices and Figure 8 shows the average reserve prices, both by scenario, for each hour of the days of week 7 of 2023, blue representing Spain and orange representing Portugal.

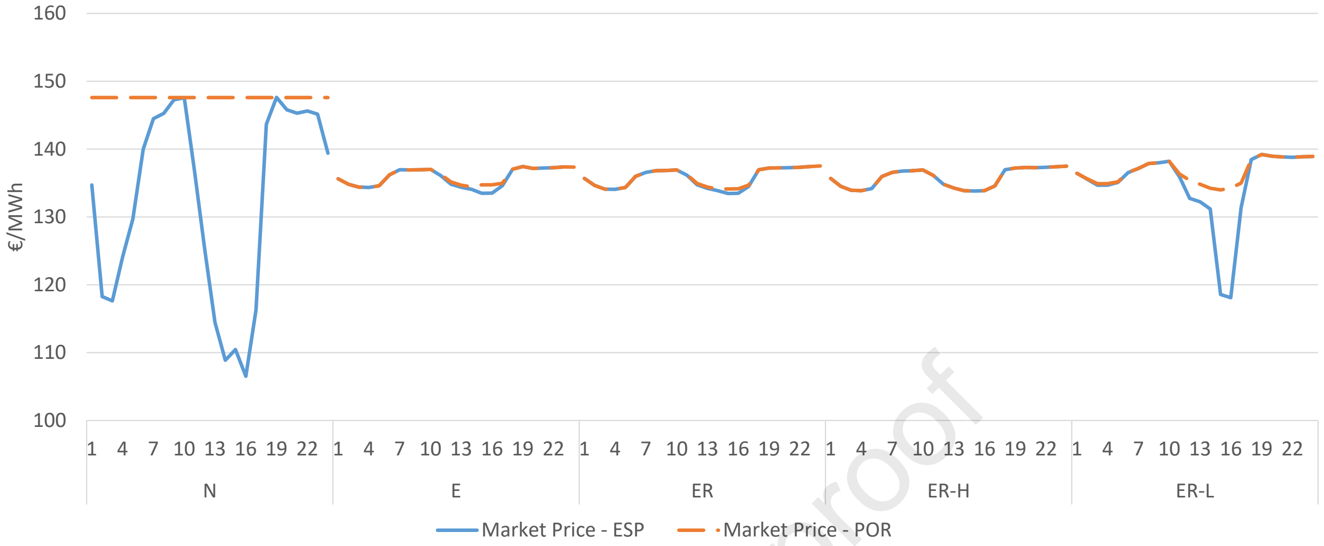

Figure 7 – Weekly average market prices by scenario, for week 7 of 2023.

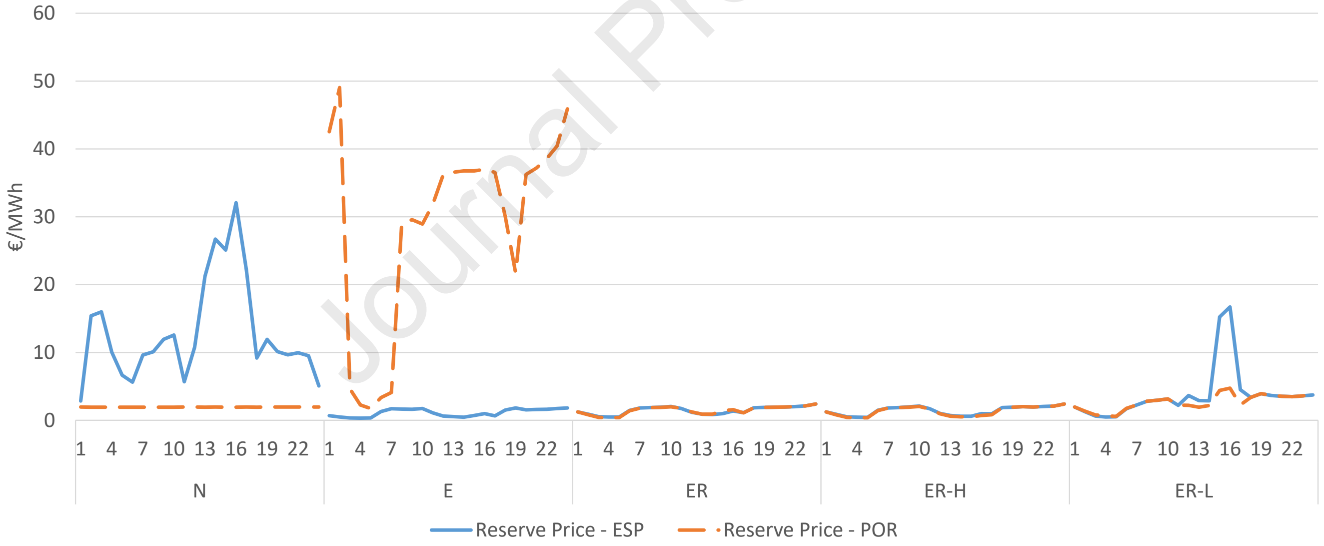

Figure 8 – Weekly average reserve prices by scenario, for week 7 of 2023.

It is noticeable that scenario N (island mode) leads to different prices for both energy and reserve commodities given that the two zones have independent markets. Scenario E (energy-only coordination) exhibits less energy market splitting between zones and fewer reserve price spikes, explained by the improved energy management coordination, but still shows significant reserve market splitting. When energy and reserve coordination are both in place, as in the three ER scenarios, there is also a significant reduction in market splitting of reserve prices compared to scenarios without such coordination.

Figure 9 shows the annual hourly average energy exchange by zone for scenarios E and ER. Positive values mean that there is an export from ESP to POR and negative values an export from POR to ESP.

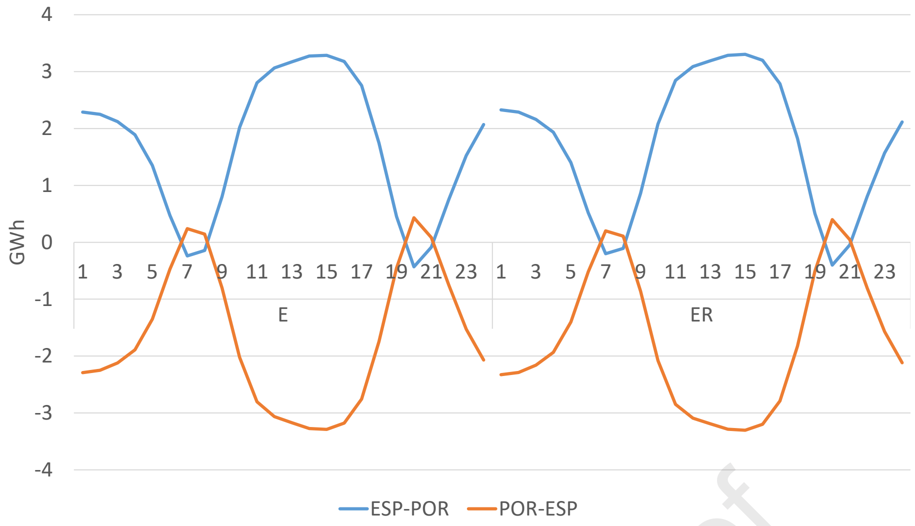

Figure 9 – Annual hourly average energy exchange by zone (GWh).

As can be seen, reserve coordination does not significantly modify the yearly average energy exchange between Portugal and Spain. Indeed, reserve amounts are low and have therefore a low impact on the interconnection capacity for energy.

Figure 10 shows the annual hourly average upper and down reserve allocation capacity by zone (i.e., the capacity allocation for reserves between ESP and POR or the other way around).

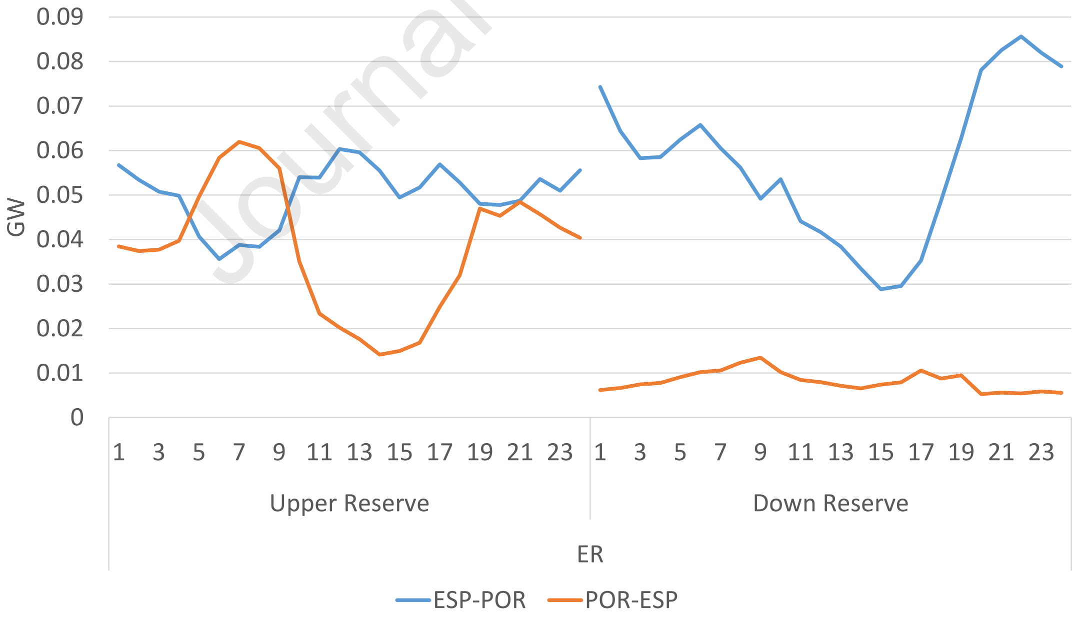

Figure 10 – Annual hourly average upper and downward reserve allocation capacity (GW).

The analysis of both figures reveals a higher allocation capacity for both upward and downward reserves in the ESP-POR direction. This is probably due to the greater available capacity for allocation (NTC) in that direction, since the NTC between Spain and Portugal is not symmetrical. Additionally, when the upward reserve allocation from ESP to POR decreases, the allocation from POR to ESP increases, which aligns with the proposed methodology – i.e. when

Spain provides upward reserves to Portugal, it does not simultaneously allocate the same transmission capacity for reserves in the opposite direction, and vice versa, due to the limited and non-symmetrical NTC between the two zones.

In contrast, the downward reserve capacity allocation does not exhibit this behaviour, since allocating capacity to downward reserves corresponds to reducing generation or increasing demand, which effectively decreases the flow on the interconnection line. As a result, downward reserves do not compete for the limited NTC in the same way as upward reserves, and their allocations in opposite directions are not mutually restrictive.

Figure 11 shows the total CO_2 emissions for the simulated scenarios.

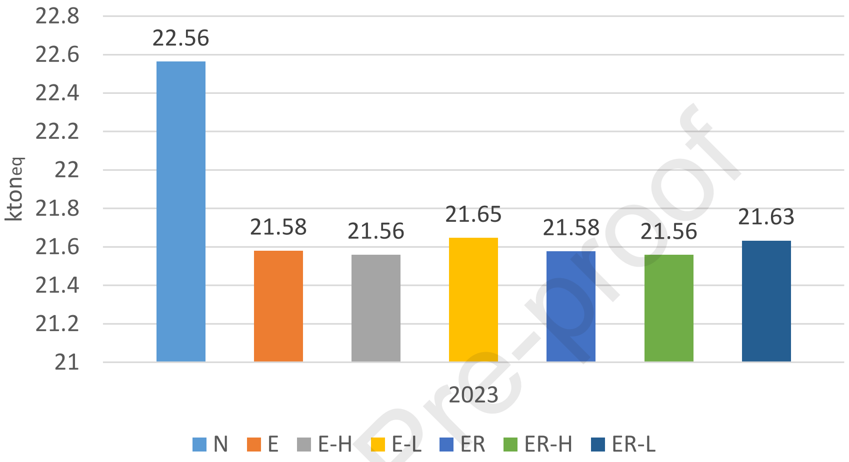

Figure 11 – Total CO_2 emissions by scenario ($kton_{eq}$).

From Figure 11:

- For the same interconnection capacity (i.e., E vs. ER, E-H vs. ER-H, and E-L vs. ER-L), coordinating reserves among zones (ER scenarios), compared to energy-only coordination (E scenarios), reduce CO_2 equivalent emissions although with a low impact.
- Scenarios E-L and ER-L, both with lower interconnection capacity, with no or lower reserve coordination to the lower capacity, CO_2 equivalent emissions increase compared to larger interconnection capacities. From E-L to ER-L, reserve coordination slightly reduces CO_2 equivalent emissions, as expected.
- Comparing larger with lower interconnection capacities always leads to a reduction of CO_2 equivalent emissions due to a better coordination, facilitating the integration of less expensive and more environmentally friendly units across different regions. This aligns with studies such as [103] that show how investments in transmission and stronger interconnection between countries may help to meet decarbonization goals.

3.4 Sensitivity analysis

To assess how different NTC values influence the total cost, Figure 12 presents the results for a new set of simulations in which line capacity varies under both the E (orange) and ER (blue) scenarios. As indicated in the horizontal axes, these simulations were conducted varying the NTC from –100% to +200% of the value initially adopted in each scenario. The figure also highlights the difference between the two cases through a green dashed line, which represents the total cost reduction achieved when coordinating energy and reserves compared to energy-only coordination.

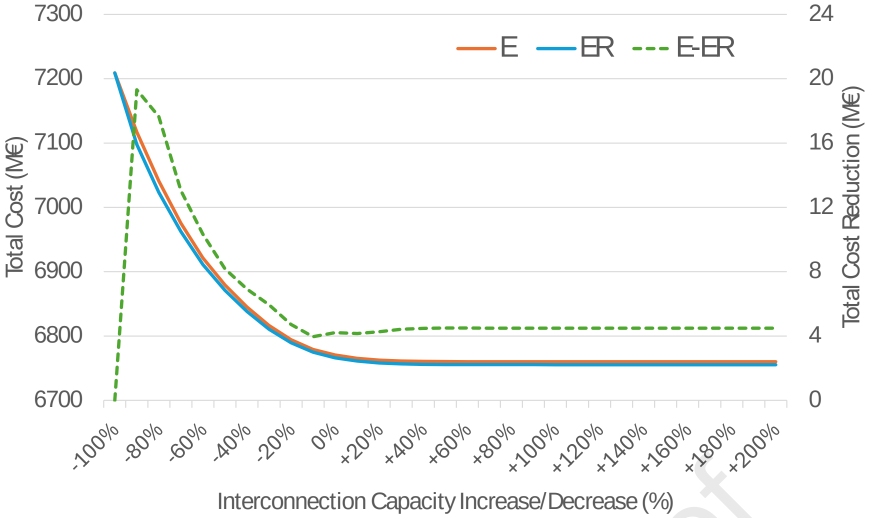

Figure 12 – Total cost of E and ER scenarios per capacity increase/decrease (main axis, blue and orange) and Total Cost Reduction (secondary axis, green) by comparing ER to E.

This figure clearly shows that coordinating energy and reserve always reduces costs regardless of the interconnection capacity among zones. This is evident by verifying that the orange line (E total costs) is always higher than the blue line (ER total costs). This cost reduction can go from approximately 4.2 M€ up to 4.5 M€, for positive capacity increments of the NTC (i.e. 0% and 100%), or obtaining a saving of 19.3 M€ with a lower NTC (i.e., -90%).

To further examine how different NTC values influence the ER results, Figure 13 and Figure 14 present a new set of simulations in which the line capacity varies only in the ER scenario, while the E base scenario remains fixed at 0% – enabling a better understanding of how an increment of capacity only for energy and reserve coordination could benefit when compared to the standard energy-only coordination.

Figure 13 shows that, at 0%, coordinating energy and reserve has a benefit of approximately 4 M€ when compared to energy-only scenario (as seen in Figure 12). However, as expected, there is a capacity where no further significant cost reduction occurs for the ER scenario when compared to the base E scenario (at 0% capacity increment), in this case corresponding to a 100% increment of the 2023 NTC values (that were, in average, 5,985.8 MWh from Portugal to Spain and 7,366.4 MWh from Spain to Portugal). In fact, by analysing the figure it is possible to conclude that cost reduction decreases significantly for capacities larger than 40%. Since transmission capacity is expensive and difficult to implement for many reasons (permissions, building, etc), there is certainly a value until which the benefits in terms of system cost reduction does not compensate the cost of building new interconnection capacity.

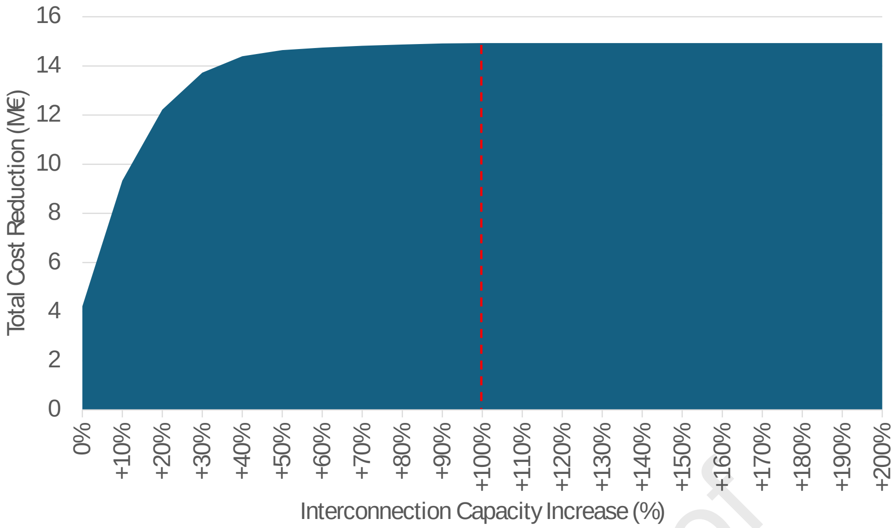

Figure 13 – Total cost reduction (when compared to 0% of capacity increase for E scenario) per percentage (%) of capacity increase for ER scenario.

On the other hand, to determine the capacity value in the ER scenario that would yield total costs comparable to those of the E base scenario, Figure 14 was developed.

This capacity value for the ER scenario that translates in similar E scenario total costs is reached for a value of -5.4% of the 2023 NTC values (resulting in a yearly average from Portugal to Spain of 2,831.3 MWh and 3,484.3 MWh from Spain to Portugal).

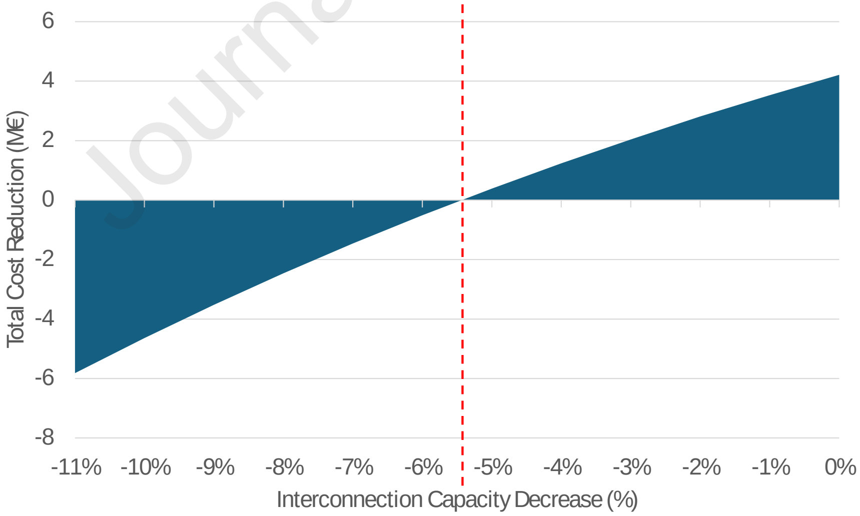

Figure 14 – Total cost reduction (when compared to 0% of capacity increase for E scenario) per percentage (%) of capacity reduction for ER scenario.

Table VI synthesizes the sensitivity analysis results previously reported in Figures 12–14, highlighting key capacity regimes through colour coding to facilitate interpretation, as explained below.

Table VI. Summary of the sensitivity results for Energy-only coordination (E) and Energy and Reserve coordination (ER).

Interc. Level	**Total costs [M€]**		**Relative cost reduction of ER to E**		**Relative cost reduction of ER to E at 0% level**	
	E	**ER**	**[M€]**	**[%]**	**[M€]**	**[%]**
-100%	7209.062	7209.062	0.000	0.00%	-438.616	-6.48%
-90%	7117.067	7097.750	19.317	0.27%	-327.304	-4.83%
-80%	7040.918	7023.272	17.647	0.25%	-252.825	-3.73%
-70%	6975.598	6962.541	13.057	0.19%	-192.094	-2.84%
-60%	6921.637	6911.300	10.337	0.15%	-140.853	-2.08%
-50%	6879.249	6871.067	8.182	0.12%	-100.620	-1.49%
-40%	6845.062	6838.144	6.918	0.10%	-67.698	-1.00%
-30%	6816.476	6810.527	5.949	0.09%	-40.080	-0.59%
-20%	6794.308	6789.583	4.725	0.07%	-19.137	-0.28%
-10%	6779.048	6775.086	3.963	0.06%	-4.639	-0.07%
-7%	6776.034	6771.903	4.131	0.06%	-1.457	-0.02%
-6%	6775.129	6770.955	4.175	0.06%	**-0.508**	-0.01%
-5%	6774.266	6770.062	4.204	0.06%	**0.385**	0.01%
-4%	6773.439	6769.210	4.229	0.06%	1.237	0.02%
0%	6770.447	6766.233	4.213	0.06%	4.213	0.06%
+10%	6765.270	6761.116	4.155	0.06%	9.331	0.14%
+20%	6762.491	6758.223	4.268	0.06%	12.223	0.18%
+30%	6761.147	6756.719	4.428	0.07%	13.728	0.20%
+40%	6760.528	6756.055	4.473	0.07%	14.392	0.21%
+50%	6760.296	6755.800	**4.495**	0.07%	14.646	0.22%
+60%	6760.195	6755.697	**4.498**	0.07%	14.749	0.22%
+70%	6760.124	6755.629	4.495	0.07%	14.817	0.22%
+80%	6760.065	6755.575	4.490	0.07%	14.872	0.22%
+90%	6760.024	6755.535	4.489	0.07%	14.911	0.22%
+100%	6760.005	6755.516	4.488	0.07%	**14.930**	0.22%
+110%	6760.003	6755.514	4.488	0.07%	**14.932**	0.22%
+120%	6760.003	6755.514	4.488	0.07%	14.932	0.22%
+130%	6760.003	6755.514	4.488	0.07%	14.932	0.22%
+140%	6760.003	6755.514	4.488	0.07%	14.932	0.22%
+150%	6760.003	6755.514	4.488	0.07%	14.932	0.22%

The grey row (0%) represents the reference case, which corresponds to the historical 2023 interconnection capacity. For this interconnection capacity, ER delivers a stable cost reduction of approximately 4.2 M€ (around 0.06%) relative to E, consistent with the baseline comparison shown in Figure 12. This case serves as the benchmark against which both capacity decreases and increases are evaluated.

Rows in red (-6% and -5% interconnection capacity) identify the break-even threshold at which joint energy and reserve coordination (ER) achieves total system costs comparable to those of the energy-only coordination (E) scenario at the reference capacity level (0%). As shown in Figure 14, this transition occurs at approximately -5.4% of the 2023 NTC values. Below this threshold, although ER always achieves lower costs than E for the same capacity level, total system costs remain comparable to those of the baseline E scenario at 0% capacity; further reductions in interconnection capacity lead to higher total costs relative to this baseline of 0% capacity for E.

Rows in yellow (+50% and +60%) represent situations in which the benefits from joint coordination do not significantly improve with larger interconnection capacity. Although total system costs continue to decrease as capacity increases, the incremental gains become small beyond this range. This behaviour mirrors Figure 13, where the cost-reduction curve begins to flatten for capacity increases above roughly +50%, indicating that transmission constraints become almost no limiting for the modelled conditions.

Finally, rows in green (+100% and +110%) correspond to the range at which additional capacity produces no further reduction in total system costs, with ER cost savings remaining effectively constant at approximately 4.49 M€. Beyond these capacity levels, further interconnection capacity expansions do not translate into additional economic gains from joint energy and reserve coordination, as transmission constraints no longer limit the allocation of either service under the modelled conditions.

4. Conclusion

This paper provides a literature review of market models regarding the coordination of EU electricity markets. The review focuses on three key areas: a) the allocation of interconnection capacity for both energy and reserves, b) market coupling mechanisms for the coordination of energy markets, and c) mechanisms for imbalance netting and the coordination of balancing reserves.

Moreover, this paper proposes a cross-border interconnection capacity allocation model that was integrated into the CEVESA market model. This representation aims at optimizing capacity allocation for both energy and reserve commodities.

Based on the improved CEVESA model, several case studies based on the MIBEL market simulation yield valuable insights into how coordination between Portugal and Spain power systems influences market prices, energy exchange, and reserve allocation. Through extensive simulation scenarios, encompassing different interconnection capacities between both countries, the results highlight the nuanced relationship between energy and reserve coordination, and explain the impacts of this coordination on system costs, emissions, and operational efficiency.

The key findings of this research and of the application of the model to the case studies are:

- Significant cost reductions from energy coordination: coordinating only energy exchanges between Portugal and Spain reduces total system costs by approximately 6.08% compared to isolated operation, in line with previous literature.
- Additional but modest gains from reserve coordination: adding reserve coordination on top of energy coordination delivers further cost reductions, typically below 0.1%, but still representing millions of euros annually in savings. These gains stem from a more efficient allocation of interconnection capacity between energy and reserve markets.
- Capacity levels influence coordination benefits: increasing Net Transfer Capacity (NTC) amplifies the benefits of coordination up to a saturation point, beyond which no significant additional savings occur. Conversely, reductions in NTC diminish coordination benefits, with notable cost increases below a critical threshold (~5.4% reduction from 2023 NTC values).
- Operational and market effects: reserve coordination reduces price splitting in reserve markets and smooths price volatility, improving market stability. However, the impact on annual average energy exchanges between countries is negligible, and CO_2 emissions remain largely unaffected, except in low-capacity scenarios where coordination facilitates cleaner dispatch.
- Robust advantage of joint coordination: across all simulated capacity levels, joint energy and reserve coordination consistently outperforms energy-only coordination in total system cost, demonstrating its robustness as a market design improvement.

Future work could extend the proposed model in several directions:

- To address the deterministic, perfect-foresight assumption on renewable availability, demand, and fuel and CO2 prices, alternative approaches could be to either adapt the model to incorporate stochastic or robust optimization models, such as [104], or designing and simulating alternative scenarios with a Montecarlo approach, being the later one of the most common approaches for such long-term analysis.
- Given that reserve requirements are treated as fixed inputs based on historical records, future work could develop alternative reserve requirement scenarios, estimating the expected needs such as in [24] or [105].
- To address the simplified NTC-based representation of cross-border exchanges and the omission of post day-ahead grid constraint impacts, future work could implement the impact of the grid constraint analysis performed by TSOs after the day-ahead market by adding constraints deduced from the detailed historical constraints imposed by TSOs to the power plants in each price zone.

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Highlights

- Joint energy and automatic reserve capacity allocation reduces total system costs.
- Reserve coordination smooths price volatility across cross-border zones.
- CEVESA market model extended for joint energy and reserve capacity allocation.
- Iberian case study shows measurable economic benefits.
- Joint coordination supports decarbonization through better market integration.

Declaration of interests

☐ The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

☒ The authors declare the following financial interests/personal relationships which may be considered as potential competing interests:

Andre Rodrigues de Oliveira reports financial support was provided by China Three Gorges Europe. Andre Rodrigues de Oliveira reports financial support was provided by Foundation for Science and Technology. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.