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# Techno-Economic Modelling and Analysis of an Evolution of Bidding Zones for Wholesale Electricity Markets in the European Power System

Thomas Brouhard

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Thomas Brouhard. Techno-Economic Modelling and Analysis of an Evolution of Bidding Zones for Wholesale Electricity Markets in the European Power System. Electric power. Université Paris-Saclay, 2022. English. NNT: 2022UPAST141 . tel-04099951

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# Techno-Economic Modelling and Analysis of an Evolution of Bidding Zones for Wholesale Electricity Markets in the European Power System

*Analyse et modélisation technico-économique d'une évolution des  
zones de prix des marchés de gros du système électrique européen*

## Thèse de doctorat de l'université Paris-Saclay

École doctorale n°575 : electrical, optical, bio : physics and engineering (EOBE)  
Spécialité de doctorat : Génie Électrique  
Graduate School : Sciences de l'ingénierie et des systèmes  
Réfèrent : CentraleSupélec

Thèse préparée au **Laboratoire de Génie Électrique et Électronique de Paris  
(Université Paris-Saclay, CentraleSupélec)**, sous la direction de **Marc PETIT**,  
Professeur à CentraleSupélec, le co-encadrement de **Martin HENNEBEL**, Maître de  
Conférences à CentraleSupélec, et la co-supervision de **Cyril GISBERT**, Ingénieur de  
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Thèse soutenue à Paris-Saclay, le 5 décembre 2022, par

**Thomas BROUHARD**

## Composition du Jury

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*"A light here required a shadow there.  
He considered. He was interested. He took it  
scientifically in complete good faith."*

Virginia Woolf, *To the Lighthouse*, 1927.



## ABSTRACT

---

In Europe, wholesale electricity markets follow a zonal market design, where bidding zones are generally defined according to administrative borders. They correspond to “**copper plate**” areas where wholesale electricity market participants are free to conduct transactions regardless of internal grid constraints, while interzonal exchanges are subject to capacity allocation.

In order to enhance market coupling and promote the penetration of renewable energy sources, European legislations such as the 2015 “Capacity Allocation - Congestion Management” network code and the 2019 “Clean energy package for all Europeans” have been promoting a review of bidding zone borders in order to highlight **structural grid constraints** – i.e. congestion phenomena that are frequent and restrictive for exchanges – into market operation.

In this PhD project, **we highlight the importance of a multidimensional and multi-horizon impact assessment for an evolution of bidding zones**, with indicators and modeling frameworks that link **system operation, market efficiency and medium- to long-term system evolution dynamics**.

Our literature review serves two main objectives. On the one hand, we put in perspective the **links between market design, congestion management and market dynamics**. We notably base this part on major real-life examples for liberalized electricity markets, including examples from the United States (PJM, CAISO), Canada (Ontario IESO), Australia (National Electricity Market) and Europe. On the other hand, we carry out **a review of modeling frameworks and publicly available data and models** used for addressing grid operation, market dynamics and investment dynamics.

Our main methodological contribution is two-fold. On the one hand, we address **the automated design of alternative zonal configurations**. For this purpose, we use **conventional clustering methods** that we apply both to an original 30-bus benchmark model and to a 2025 European static grid model. In both cases, we adapt the

use of clustering to target both more efficient congestion management and the relative preservation of existing market dynamics. The resulting configurations are then evaluated in terms of **congestion management, price formation, and the overall distribution of costs and revenues in the system, under 2025, 2030 and 2040 dispatch scenarios**. Our clustering efforts are based on series of locational marginal prices obtained from DC optimal power flow simulations. In particular, our network model is aligned with the "National Trends" scenario of the 2020 edition of ENTSO-E's Ten-Year Network Development Plan (TYNDP).

On the other hand, we use reduced models derived from previously obtained candidate delineations to perform simulations that combine capacity expansion planning and unit commitment on a 2025 to 2040 period. We notably include input time series from ENTSO-E's 2021 edition of the European Resource Adequacy Assessment (ERAA). We therefore **illustrate the general influence of bidding zone revision on generation, interconnection and market dynamics**, with a discussion of **the sensitivity of our results to investment dynamics and cross-zonal exchange capacities**.

## RESUME

---

En Europe, les marchés de gros de l'électricité suivent un market design zonal, où les bidding zones sont généralement définies en fonction des frontières des états membres. Ces zones de prix correspondent à des "**plaques de cuivre**" où les acteurs de marché sont libres d'effectuer des transactions sans limite de volume, tandis que les échanges interzonaux sont sujets à des limitations liées aux contraintes réseau..

Afin de renforcer le couplage des marchés et de favoriser la pénétration des énergies renouvelables, des législations européennes telles que le code de réseau " Capacity Allocation - Congestion Management " de 2015 et le " Clean energy package for all Europeans" de 2019 avancent la possibilité **d'une révision du tracé des bidding zones**. Le principe est ainsi de mettre en évidence les contraintes structurelles du réseau - c'est-à-dire les phénomènes de congestion fréquents et contraignants pour les échanges - dans les opérations de marché.

Dans ce projet de thèse, nous soulignons l'importance **d'une évaluation multidimensionnelle et multi-horizon de l'impact d'une évolution des bidding zones**, avec des indicateurs et des outils de modélisation qui font le lien entre **fonctionnement du système, processus de marché et dynamiques d'évolution du système électrique à moyen et long terme**.

Notre revue de littérature sert deux objectifs principaux. D'une part, nous mettons en perspective **les liens entre market design, gestion des congestions et dynamiques de marché**. Nous nous appuyons notamment sur des exemples internationaux de systèmes électriques libéralisés,, notamment aux Etats-Unis (PJM, CAISO), au Canada (Ontario IESO), en Australie (National Electricity Market) et en Europe. D'autre part, nous détaillons **les types d'outils et les données publiques mobilisables pour modéliser le fonctionnement du réseau, les dynamiques de marché et les tendances d'investissement**.

Nous proposons deux principales approches méthodologiques. D'une part, nous abordons la **construction automatisée de configurations zonales alternatives**. Nous utilisons pour cela des **méthodes de clustering conventionnelles**, que nous appliquons à la fois à un modèle de test original à 30 nœuds et à un modèle 2025 du système électrique européen. Dans les deux cas, nous adaptons l'utilisation du clustering pour cibler à la fois une gestion plus efficace des congestions et la préservation relative des dynamiques de marché existentes. Les configurations obtenues sont ensuite évaluées **à l'aune de la gestion des congestions, de la formation des prix et de la répartition générale des coûts et des revenus entre les principaux acteurs du système, le tout pour des scénarios de dispatchs 2025, 2030 et 2040**. En particulier, nos efforts de clustering s'appuient sur des séries de prix nodaux obtenus par simulations d'optimal power flow en courant continu. Notre modèle de réseau est notamment aligné sur le scénario « National Trends » de l'édition 2020 du Ten-Year Network Development Plan de l'ENTSO-E.

D'autre part, nous incluons une étape de réduction de réseau ciblant deux configurations zonales alternatives obtenues précédemment, et nous introduisons des simulations qui combinent capacity expansion planning et unit commitment sur une période de 2025 à 2040. Pour cela, nous intégrons notamment des séries temporelles issues de l'édition 2021 du European Resource Adequacy Assessment (ERAA) de l'ENTSO-E. Cette étape illustre ainsi **l'influence générale d'une révision des bidding zones sur les dynamiques de génération, d'interconnexion et sur les dynamiques de marché**. Nous intégrons également une **analyse de sensibilité qui fait intervenir les tendances d'investissement dans le parc de production et des variations des capacités d'échanges entre les zones**.

## REMERCIEMENTS

---

Je remercie mes rapporteurs Raphaël Caire et Hossein Farahmand pour leur lecture attentive et leurs précieux retours sur mon travail, ainsi que les autres membres du jury qui m'ont offert une discussion très enrichissante lors de ma soutenance.

Mes remerciements vont également à mon directeur de thèse Marc Petit et à mon encadrant Martin Hennebel pour son suivi au quotidien. Martin, mes compliments sur ta sollicitude – en particulier dans des périodes de confinement - et la pertinence de tes conseils ne font que s'ajouter à ce que disent déjà de toi tes étudiants. Une pensée particulière va également à mon encadrant industriel Cyril Gisbert, qui a porté ce projet de thèse avant même mon arrivée : merci d'avoir su m'aider à valoriser mon travail à chaque étape tout en garantissant des conditions excellentes pour la réalisation de ma thèse.

Je salue également toutes les personnes que j'ai côtoyées au département SYSTEME d'EDF R&D et au laboratoire GeePs à CentraleSupélec. Votre accueil et nos échanges – même à distance - ont contribué à créer un environnement remarquable pour mes travaux. Merci en particulier à mes collègues du projet DRIIME à EDF R&D, parmi lesquels j'ai trouvé une ambiance excellente et toujours au moins un binôme pour avancer sur des questions de fond.

Je souhaite aussi mentionner certains de mes anciens enseignants à l'école des Mines qui, en amont, m'ont aidé à cultiver ma recherche d'expertise et à cibler un projet de thèse dans lequel je puisse m'épanouir de la sorte. Je pense en particulier à Jérôme Denis, Brice Laurent et Liliana Doganova.

Ce travail doit également beaucoup à plusieurs docteurs de mon entourage qui, en éclairant la voie, m'ont aidé à aborder au mieux chaque étape, notamment Simon Thomas et Alexandre Fossati. Leander Kotzur, je suis ravi de pouvoir te rendre tes remerciements à cette occasion.

Valentin Drouet occupe bien sûr une place fabuleuse dans cette

catégorie. Merci pour tout ce que tu as fait pour ma soutenance et avant. Cerise sur le gâteau, merci à Maxime Breiller-Laverdure d'avoir mis ma vidéo de *Ma thèse en 180s* à son *legenda*. Roman Solé-Pomiès, je pense à toi en terminant ces années – et quelques heures – d'études parcourues ensemble. Audren Mauplot, merci d'avoir un peu fait cette thèse avec moi.

Je remercie toutes les personnes qui étaient présentes à ma soutenance et à mon pot de thèse – ou à l'un des deux, même à distance et même rapidement. J'ai commencé la rédaction de ce manuscrit seul quelque part à proximité du pylône 92 de la liaison 225kV N°1 Cornier - Saint-Triphon, c'était un plaisir d'en partager l'accomplissement avec vous. Je termine sur un remerciement adressé à mes parents : il y a beaucoup de vous dans ce qui m'a permis de suivre ce parcours – et d'en être aussi content aujourd'hui.

**Thomas**

## ABBREVIATIONS

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<b>ACER</b>	European Union Agency for the Cooperation of Energy Regulators
<b>AEMO</b>	Australian Energy Market Operator
<b>ATC</b>	Available Transfer Capacity
<b>Australian NEM</b>	Australian National Electricity Market
<b>CACM</b>	Capacity Allocation - Congestion Management
<b>CAISO</b>	California Independent System Operator
<b>CEP</b>	Clean Energy Package
<b>CHP</b>	Combined Heat and Power
<b>CWE</b>	Central Western Europe
<b>DC</b>	Direct Current
<b>ENTSO-E</b>	European Network of Transmission System Operators for Electricity
<b>ERAA</b>	European Resource Adequacy Assessment
<b>EU</b>	European Union
<b>FBMC</b>	Flow-Based Market Coupling
<b>GME</b>	Gestore dei Mercati Energetici
<b>HVDC</b>	High Voltage Direct Current
<b>LMP</b>	Locational Marginal Price
<b>MILP</b>	Mixed-Integer Linear Programming
<b>NT</b>	National Trends

<b>Ontario IESO</b>	Ontario Independent Electricity System Operator
<b>OPF</b>	Optimal Power Flow
<b>PECD</b>	Pan-European Climatic Database
<b>PEMMDB</b>	Pan-European Market Modelling DataBase
<b>PJM Interconnection</b>	Pennsylvania - New Jersey - Maryland Interconnection
<b>PTDF</b>	Power Transfer Distribution Factor
<b>PV</b>	Photovoltaic
<b>PyPSA</b>	Python for Power System Analysis
<b>RE</b>	Redispatch Effort
<b>RES</b>	Renewable Energy Sources
<b>RoR</b>	Run-of-River
<b>TSO</b>	Transmission System Operator
<b>TYNDP</b>	Ten-Year Network Development Plan
<b>UC</b>	Unit Commitment
<b>UCTE</b>	Union for the Coordination of Transmission of Electricity
<b>VaR</b>	Value at Risk

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## GENERAL INTRODUCTION

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In Europe, wholesale electricity markets follow **a zonal market design, where bidding zones generally correspond to national borders**. These wholesale market areas can be seen as **“copper plate” perimeters** where market participants are free to conduct transactions without limitation in volumes. On the other hand, cross-zonal commercial exchanges are limited to **market coupling constraints** that reflect the physical constraints of the transmission grid.

In order to both enhance market coupling and allow more efficient penetration of low-carbon electricity sources, successive European legislations have been promoting **a possible revision of the bidding zone borders** in the past few years. In particular, the underlying rationale is **to align zone delineations with structural congestions** – i.e. bottlenecks that are frequent and restrictive for cross-zonal exchanges – as a means to better highlight grid constraints into market operations.

In particular, several **large-scale institutional Bidding Zone Review efforts** have been initiated since the enactment of the “Capacity Allocation – Congestion Management” network code in 2015 (European Commission, 2015). In particular, the European Union Agency for the Cooperation of Energy Regulators (ACER) recently issued **a series of zone revision proposals based on 2025 projections** of the European power system.

In this work, we highlight the importance of a **multidimensional and multi-horizon approach to the evolution of European bidding zones** for wholesale electricity markets. We therefore focus on **indicators and modelling frameworks that link system operation and market dynamics on a short to long-term perspective**.

The present thesis is organized in **five chapters**. In Chapter 1, we put in perspective the **links between market design, system operation and market dynamics** through a literature review that combines academic, industrial and institutional publications. We notably include a literature review on congestion management, a comparative study

of major power systems in the world, and a chronology of institutional efforts regarding bidding zone revision.

Chapter 2 introduces the **main modelling frameworks and input data** that will be featured in the rest of the chapters. We notably justify our use of optimal power flow simulations with direct current approximation, present the elaboration of a 30-bus benchmark model and the construction of our large-scale European case study.

Chapter 3 discusses the **automated design of alternative zone configurations**, and presents our efforts to adapt conventional clustering frameworks to this problem. We notably highlight an approach that combines operational benefits and the overall preservation of status quo market dynamics, which results in **series of illustrative zone reconfiguration scenarios** for both our benchmark case and the European power system.

In Chapter 4, we present our **indicators and methodologies for assessing previously obtained candidate zone configurations**. We notably discuss the performances of these zone configurations regarding congestion management, price formation and the distribution of system costs and revenues from a short- to long term perspective.

In Chapter 5, we focus on **two specific alternative European zone configurations** and introduce **a complementary simulation chain** that combines **capacity expansion planning and unit commitment** modelling frameworks. This approach extends the analysis of Chapter 4, further addressing **the impacts of alternative system trajectories involving generation investment dynamics and variations of cross-zonal exchange capacities**.

We finally present a general conclusion that summarizes our main contributions, main findings and perspectives for future works.

While our large-scale European case studies are based on realistic modelling assumptions from publicly available models and data, they mostly correspond to system projections established until 2020 – see (ENTSO-E, 2020d, 2021c). **These projections are likely to be significantly revised in the years to come** in light of the

consequences of the Covid-19 pandemic and the current global energy crisis.

However, the alternative zone configurations presented in this thesis are most of all intended to **illustrate general trends and patterns regarding zone revision**. Our approach is therefore not to be understood as a formal assessment of the feasibility of specific zone reconfigurations, but as an effort to **highlight structural impacts of bidding zone revision from a multidimensional and multi-horizon perspective**. In particular, the featured methodologies and indicators could be **easily adapted to updated short- to long-term evolution scenarios for the European power system**.



# 1 BIDDING ZONE REVISION IN THE MARKET DESIGN TOOLBOX

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In the 2019 “Clean Energy for all Europeans” package (CEP) (European Commission, 2019), which introduces a set of new rules related to 2030 energy transition targets, the European Commission highlights two main purposes regarding the evolution of electricity market designs. First, several references are made to the objective of “making the electricity market in the EU better suited to variable and intermittent renewable energies”, in line with decarbonation objectives. In parallel, this valorization of low-carbon energy sources is envisioned as part of a “framework for cross-border cooperation”, which is summarized by the expression “decarbonization on the one hand and security of supply on the other”.

This ambition has notably been reaffirmed in 2022 in the context of the “Fit for 55” package of the European Green Deal (European Commission, 2022). The proposal notably includes a 32% to 40% raise of the 2030 objective regarding the share of renewable energy sources in the finale energy consumption, and pushes for higher cross-zonal cooperation notably through the use of long-term power purchase agreements.

While security of supply is not directly linked to market coupling, this kind of statement directly refers to major ongoing transformations of the electric industry. In particular, the quick, sustained and spatially heterogeneous development of renewable energy sources represents a challenge for standard power system operation, raising the issue of efficient grid development (ENTSO-E, 2021d). In the short run, this notably creates a situation where specific European countries are facing rising congestion management costs, which sometimes amount to billion euros per year (ENTSO-E, 2021a).

In this context, **European legislations have been promoting means to enhance system operation performances**. The 2015 “Capacity Allocation – Congestion Management” network code (European Commission, 2015) notably binds transmission system operators to carry out a triannual evaluation of the implemented bidding zone configuration (ENTSO-E, 2021a), notably focusing on the frequency and location of grid constraints and the resulting congestion costs and volumes. The CACM network code also triggered the Bidding Zone Review process (ENTSO-E, 2018b), which aims to propose alternative

bidding zone configurations in accordance to structural grid congestion.

The Clean Energy Package (CEP) reinforced the hypothesis of a reconfiguration of specific bidding zones by establishing a new standard for cross-zonal exchanges. In particular, this legislation sets a 70% minimum threshold regarding the availability of cross-zonal capacities in proportion to the physical capacity of interconnectors.

In this chapter, **we put in perspective the role of bidding zone revision as a market design tool**. In Section 1.1, we introduce fundamental concerns regarding wholesale electricity market coupling and congestion management. Section 1.2 then explores the links between market design and system operation through a worldwide overview of major power systems. Finally, Section 1.3 gets back to the institutional and academic discussions over a possible revision of European bidding zones for wholesale electricity markets.

From a more general perspective, this chapter intends to justify the need for a comprehensive approach to the evolution of bidding zones, taking into account system operation performances, market dynamics and general alignment with long-term system projections.

## 1.1 SYSTEM OPERATION IN THE TIME OF ENERGY TRANSITION

As previously mentioned, current institutional discussions of the bidding zone configuration tend to target specific concerns regarding congestion management and the enhancement of cross-zonal exchanges.

In this section, **we address the link between bidding zone delimitation and the dynamics of wholesale electricity markets.** We specifically discuss the possible impact of bidding zone revision on market coupling and we present a literature review on the emerging challenges regarding congestion management. **We thereby identify structural links between system operation, price formation and the resulting medium- to long-term investment dynamics.**

### 1.1.1 Fundamentals of Market Coupling

As mentioned in the introduction, pricing in European wholesale electricity markets abides a zonal design. This implies that spot market prices – which includes Day-Ahead and Intraday market processes – are uniform over specific market areas called bidding zones. Under competitive market conditions, there is therefore no volume limitation in the electricity exchanges contracted between market participants of a same zone.

In this perspective, generation resources are distinguished by a merit-order based on their available capacity and marginal costs. Under these short-term, competitive conditions, the zonal price therefore converges towards the cost of the last megawatt-hour produced in order to meet residual demand – which integrates cross-zonal exchanges and fatal generation. Further details and a discussion on marginal cost discontinuities can be found in (Ventosa, Linares and Pérez-Arriaga, 2013).

Let us consider the IEEE 30-bus system, as described in (*30 Bus Power Flow Test Case, 1993*), which single-line diagram is presented in Figure 1.1 (Source (Peyghami *et al.*, 2019)). Capacity and cost characteristics for the six generators are presented in Table 1.I. For the purpose of this example, the marginal cost and capacity of the generator located at bus 8 have been modified.

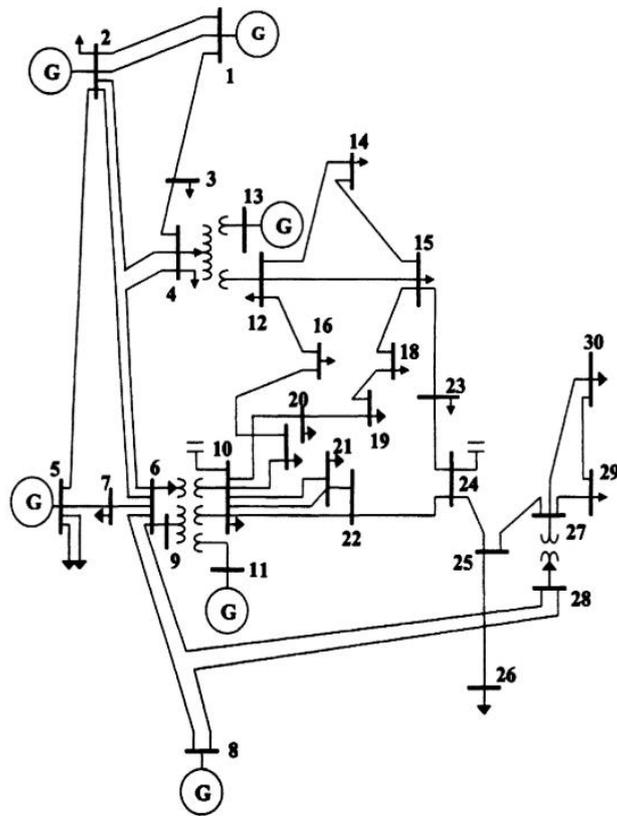


Figure 1.1: IEEE-30 Bus System - Single-Line Diagram.

Table 1.1: IEEE-30 Bus System – Generator Characteristics.

Bus	Pmax (MW)	Marginal Cost (€/MWh)
1	200	37.5
2	80	175
5	50	625
8	(35) 45	(83,4) 175
11	30	250
13	40	250

Traditionally, the cumulated electricity demand for this IEEE test case is 285 MWh (*30 Bus Power Flow Test Case*, 1993). **Let us first consider a single bidding zone that encompasses the whole system.** Under the assumption that demand is inelastic to price – meaning that consumers will pay any price to meet their electricity needs, and after application of the zonal merit order, we obtain the following supply and demand curves. Demand is therefore met for a zonal price of 175€/MWh.

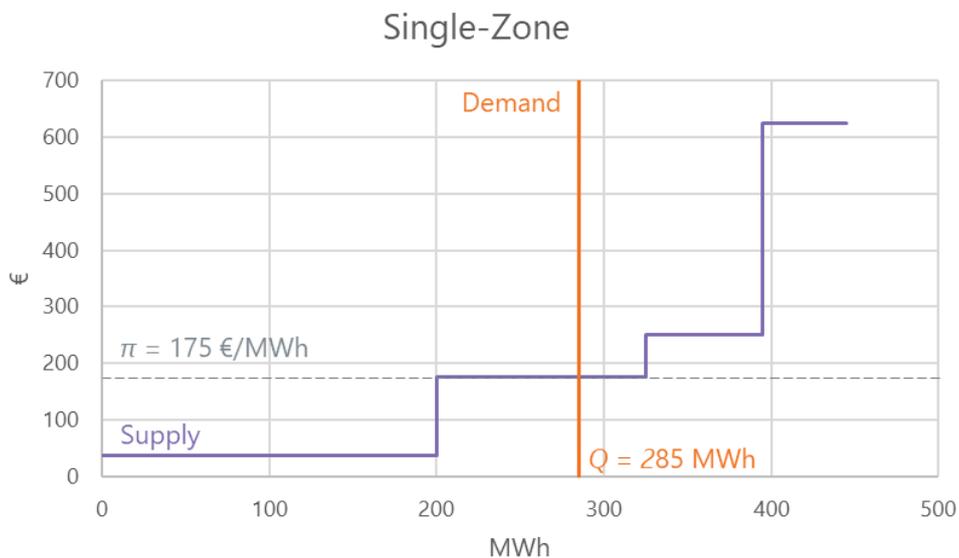
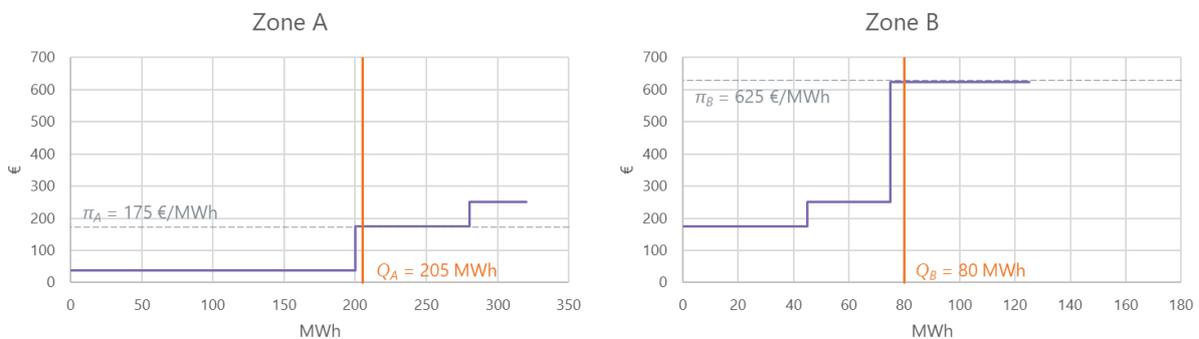


Figure 1.2: Zonal Price Formation - Single Zone.

**Let us now assume that the system is arbitrarily divided into two bidding zones**, with generators from buses 1, 2 and 13 in zone A, and generators from buses 3, 5 and 8 in zone B. In proportion to the installed generation capacities, we assume that the demand in zone A is 205 MWh, while the demand of zone B is 80 MWh.

In the absence of cross-zonal power exchanges, updated zonal supply curves result in two different zonal prices: the 175€/MWh is preserved in zone A, while the zonal price of zone B soars to 625 €/MWh – see Figure 1.3.



*Figure 1.3: Zonal Price Formation - Two Zones Without Market Coupling*

If we take cross-zonal exchanges into consideration, it becomes clear that consumers from zone B will tend to buy cheaper energy from zone A. Figure 1.4 represents two scenarios for zonal price formation, in case of a power transfer from zone A to zone B of 20 and 40 W respectively.

In both cases, the power transfer increases the net demand of the exporting zone (zone A), while additional power supply is reported on the merit-order of the importing zone (zone B). In fact, the energy contracted by zone A producers ( $Q'_A$ ) increases at the expense of the energy contracted by producers in zone B ( $Q'_B$ ), which tends to reduce the price differential between zones. Considering the generators at stake, the 20MW transfer results in a price drop to 250€/MWh in zone B. On the other hand, the 40MW transfer allows the system to reach price convergence over a price of 175€/MWh.

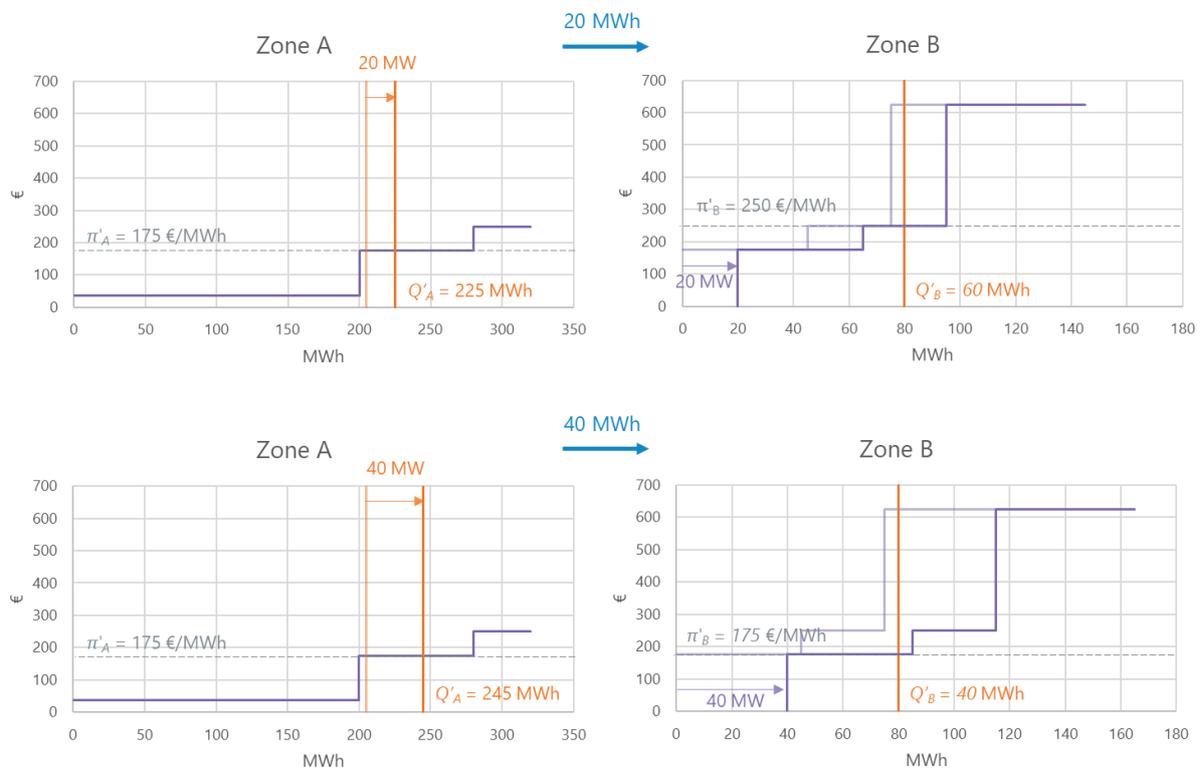


Figure 1.4: Zonal Price Formation - Two Zones With Market Coupling

Regardless of grid constraints, the equilibrium of market coupling is therefore reached when zonal prices become identical.

Moreover, while both 20 and 40 MW power transfers result in the the same zonal prices, corresponding generator dispatches are not identical. In fact, market coupling affects the overall distribution of cost and revenues between consumers, producers and transmission system operators. Figure 1.5 shows how fundamental economic indicators can be deduced from the diagrams of Figure 1.4. In particular, we highlighted:

- The total **generation cost**, which here does not include the cost of possible redispatching actions;
- The **cost of consumption**, which corresponds to the sum of zonal demands valued at zonal prices;
- **Producer margins**, which is the difference between total producer profit and the total cost of generation;

- **Gross congestion rents**, which is the volume of energy transferred valued at the price spread between zones, and is a source of revenue for transmission system operators.

The values of the four indicators for each market coupling scenario and for the single-zone configuration is presented in Figure 1.5. While the presence of two separate zones tends to dramatically increase consumption costs and producer margins compared to the single-zone configuration, market coupling tends to help bringing these values near a single-zone level – with an additional congestion rent for TSOs.

In particular, this example illustrates that the congestion rent is zero both in the absence of cross-zonal capacity and in case of price convergence, and positive when price spreads remain between connected zones. This makes this revenue a relevant signal for investment in grid reinforcements. The interactions between indicators as well as the impact of congestion costs will be further discussed in Chapter 4.

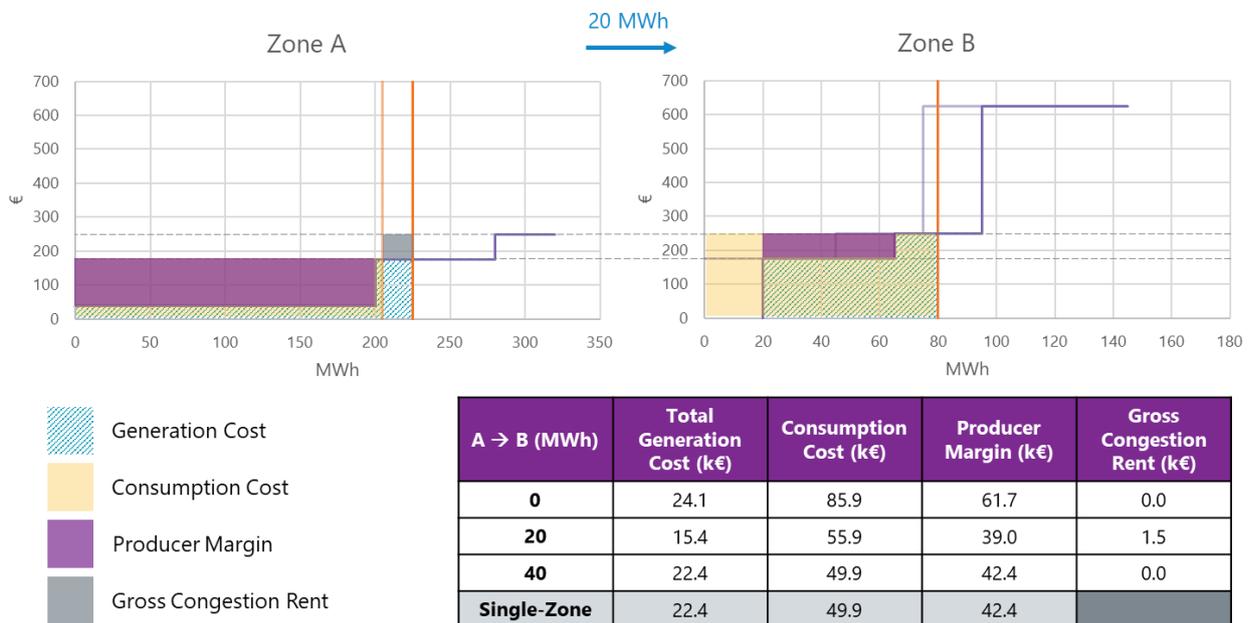


Figure 1.5: An Illustration of Economic Transfers Between Consumers, Producers and TSOs.

In general, this examples illustrates how amendments in the bidding zone delineation – here a split into two zones – can create price spreads over a given area, but most of all **trigger structural transfers of cost and revenues between consumers, producers and transmission system operators**. From a more strategic point of view, this example shows how bidding zone revision can be incitative for developing market coupling over specific areas – potentially leading to grid reinforcement.

Under the assumption that zone delineations are aligned with structurally constrained network elements, **this evolution of market design therefore highlights grid constraints into zonal market processes** – while generating revenue for TSOs that are burdened with congestion costs.

While our 20 and 40 MWh transfer volumes were chosen arbitrarily for the sake of this example, the consideration of grid constraints in the calculation of cross-zonal capacities is essential to zonal market processes. In particular, it is important to bear in mind that **market coupling mechanisms specifically take into account all network elements that are susceptible of limiting commercial exchanges between zones**.

In particular, Van den Bergh et al. (Van Den Bergh, Boury and Delarue, 2016) identify two main approaches to capacity calculation in Europe: Net Transfer Capacities (NTC) on the one hand, and Flow-Based Market Coupling on the other (FBMC).

Let us consider a system with three zones named A, B and C (see Figure 1.6), in a given dispatch configuration - i.e. for a specific time step. Let us define zonal net positions as the difference between incoming and outgoing flows for a given zone. This can be interpreted as a net exchange volume that we will note  $(NEx_Z)_{Z \in \{A,B,C\}}$ . Let  $CB$  be the set of critical branches in the system, i.e. the predefined set of lines that are susceptible of limiting exchange capacities, which includes both cross-zonal and internal lines. Critical branches are generally designated as critical network elements and contingencies (CNECs)

within institutional publications (ENTSO-E, 2018b). Let  $(f_l)_{l \in CB}$  be the oriented power flow on critical branches.

Flow-Based Market Coupling requires two main inputs. First, it is based on the estimation of power transfer distribution factors  $(PTDF_{Z \rightarrow l})_{(Z,l) \in \{A,B,C\} \times CB}$ . These linear coefficients represent the influence of a change of net position of a given zone on the flow of a specific critical branch.

On the other hand, Remaining Available Margin  $(RAM_l)_{l \in CB}$  of each critical branch is also necessary. It corresponds to the share of the line physical capacity that remains available once specific values are removed, including security margins and flows contracted on other markets (e.g forward markets, bilateral trades). In particular, the CEP70 criteria that we mentioned in the introduction of this chapter specifies that the level of commercial flows – which mostly corresponds to the RAM - on the interconnectors of each border should amount to at least 70% of their nominal rating.

More details on RAM and PTDf computation can be found in (Van Den Bergh, Boury and Delarue, 2016). Equations 1.1 and 1.2 present the corresponding FBMC constraints, with  $(\varphi_l^0)_{l \in CB}$  representing the base case flows when all net positions are considered zero. Each combination of zone and critical branch therefore provide a linear constraint that contribute to the definition of a so-called Flow-Based domain. This defines **the field of zonal exchange configurations that are physically possible for a given multi-zonal market interval**.

$$-RAM_l \leq f_l \leq RAM_l ; \forall l \in CB \quad (1.1)$$

$$f_l = \sum_{Z \in \{A,B,C\}} PTDF_{Z \rightarrow l} NE x_Z + \varphi_l^0 ; \forall l \in CB \quad (1.2)$$

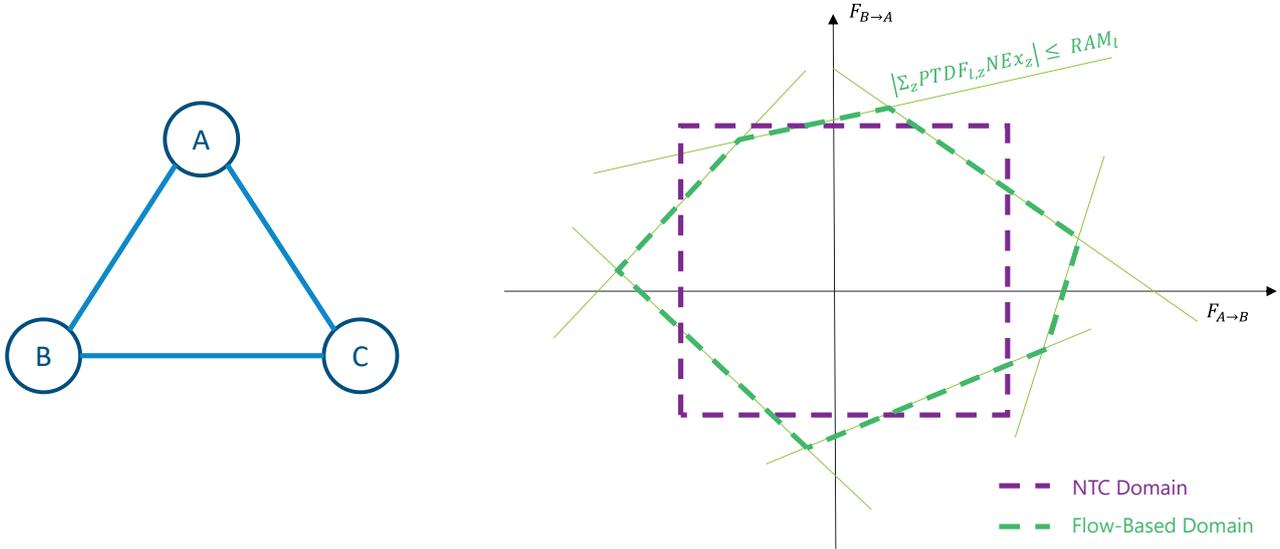


Figure 1.6: Flow-Based and NTC domains on a Three-Zone Example.

Let  $(F_{X \rightarrow Y})_{X,Y \in \{A,B,C\}}$  be the set of oriented power flows on zone borders. A visualization of a possible Flow-Based domain on our three-zone example is presented on Figure 1.6.

On the other hand, Net Transfer Capacities rely on the estimation of upper and lower bounds for the flow of each critical branch, which is synthetized in Equation 1.3 and illustrated on Figure 1.6.

$$NTC_l^{\min} \leq f_l \leq NTC_l^{\max} ; \forall l \in CB \quad (1.3)$$

While the interdependence between zone borders and critical branches is not as explicitly taken into account under NTC market coupling, the resulting exchange capacity still encompasses all critical network branches. Moreover, the determination of NTC flow bounds by transmission system operators includes **margins that integrate both interdependencies between borders and additional technical considerations** - notably voltage stability (European Transmission System Operators, 2000).

Under these considerations, we therefore insist on the fact that **zonal market coupling does not imply a disregard of intrazonal grid constraints**. In fact, this market design allows the **operation of vast and unconstrained market areas while managing most grid constraints through market coupling processes** – and occasional redispatching actions.

In this context, a revision of bidding zones can be envisaged as a means to avoid situations where intrazonal critical branches affect cross-zonal exchanges. In line with the Electricity Regulation under the Clean Energy Package, ENTSO-E specifically recalls that “Bidding zones shall not contain such structural congestions unless [...] those structural congestions do not lead to reductions in cross-zonal trading capacity” (ENTSO-E, 2021a). On a more general perspective, the immediate operational impact of a bidding zone revision would be to **enhance the consideration of particularly constrained lines within zonal market processes**. This is susceptible of reducing the costly redispatching actions that become necessary when the zonal dispatch obtained at market clearing becomes unsustainable regarding grid constraints. This is specifically the case whenever the day-ahead capacity allocation becomes obsolete on an intraday basis.

### 1.1.2 Managing Congestion: A Literature Review

The current delineation of European bidding zones is mostly based on national borders. While reflective of the historically national development of transmission grids (Réseau de Transport d'Électricité, 2021), this situation is also **in alignment with current fiscal and legal systems as well as domestic tariff equalization**. It is also useful regarding the readability of price formation and producer access to compensation through redispatching. In particular, examples for congestion-based zone revision remain rare and limited to specific regions, like with the revision of Nordic bidding zones in 2011 (Makkonen and Viljainen, 2012) or the 2018 split of the German-Austrian area (ENTSO-E, 2021a).

Emerging discussions regarding a Pan-European alignment of the bidding zone configuration to system operation criteria are therefore unprecedented, and fundamentally linked to current transformation of the electric industry. In particular, **the accelerating pace of the integration of renewable sources, mostly intermittent and very heterogeneously distributed on the grid, tends to create operational challenges**. This is notably due to the fundamental inertia of grid development, especially with respect to investment costs, construction times and underlying political stakes. In the literature, the mutation of the power industry mutation is also observable through innovative methodologies and case studies in contributions addressing congestion management.

Table 1.II presents a selection of articles that evaluate the performance of congestion management in relation to various explanatory variables. Fundamentally, the topic of congestion management is frequently studied through the performance of various market design or congestion management methods. This is associated with contributions comparing zonal and nodal pricing (Dijk and Willems, 2011; Sarfati and Hesamzadeh, 2013), redispatching and countertrading mechanisms (Oggioni and Smeers, 2013; Higgins *et al.*, 2015; Diop, 2020), centralized and decentralized congestion management (Singh, Mahanty and Singh, 2015) or even different bid formats in a context of competitive adjustment mechanisms (Huang, Bompard and Yan, 2011). While the most common modelling

framework remains optimal power flow simulation, dynamic market simulations are also frequent when it comes to contingency analysis (Breuer *et al.*, 2011), adequacy studies (Delgadillo and Reneses, 2013).

On the other hand, more and more contributions address links between congestion management and the deployment of emerging services and generation sources. Recent contributions therefore explore the potential behind demand flexibility aggregators (Kunz and Zerrahn, 2015; Pantoš, 2020)), massive energy storage (Prajapati and Mahajan, 2021), cogeneration units (Schermeier, Vergara and Fichtner, 2018) and distributed energy resources (Singh and Parida, 2013). The impact of greenhouse gas emission limitation measures on congestion costs is also explored in (Reza Salehizadeh, Rahimi-Kian and Oloomi-Buygi, 2015).

This literature review on congestion management is illustrative of how **emerging generation and flexibility resources are not only considered for their impact on congestion phenomena, but also for their possible contribution to performant system operation**. This diversification of research topics also echoes institutional productions such as ENTSO-E's "Vision on Market Design and System Operation towards 2030" (ENTSO-E, 2019c), an anticipatory exercise that explores the articulation of possible market design evolutions – including bidding zone revision but also capacity remuneration – and emerging technical challenges like the integration of meshed HVDC networks or the valorization distributed flexibilities.

In this context, the possibility for bidding zone revision therefore appears as **part of a market design toolbox**, and is associated with both short-term operational objectives and medium- to long-term visions of the European power system.

Table 1.II: Congestion Management: A Literature Review.

Ref.	Year of Publication	Studied System	Studied Period	Main Methodology			Explanatory Variables				
				OPF	Market Simulation	Data Correlation	Zonal v. Nodal	Corrective Actions	Flexibility Services	Contingency Analysis	Emission Limitations
(Huang, Bompard and Yan, 2011)	2011	IEEE 30-bus test system	N/A	✓	✓			✓			
(Dijk and Willems, 2011)	2011	2-zone test system	N/A		✓		✓				
(Breuer <i>et al.</i> , 2011)	2011	CWE	2020	✓	✓			✓		✓	
(Singh and Parida, 2013)	2013	39-bus New England test system	N/A	✓					✓	✓	
(Sarfati and Hesamzadeh, 2013)	2013	IEEE 24-bus model	N/A	✓			✓				
(Oggioni and Smeers, 2013)	2013	6-bus test grid	N/A	✓				✓			
(Delgadillo and Reneses, 2013)	2013	IEEE 24-bus model	N/A		✓					✓	
(Singh, Mahanty and Singh, 2015)	2015	Modified IEEE-30 bus system	N/A	✓				✓			
(Reza Salehizadeh, Rahimi-Kian and Oloomi-Buygi, 2015)	2015	IEEE 24-bus model	N/A		✓						✓
(Kunz and Zerrahn, 2015)	2015	Germany	2011	✓				✓	✓		
(Higgins <i>et al.</i> , 2015)	2015	United Kingdom	2016		✓			✓	✓		
(Scher Meyer, Vergara and Fichtner, 2018)	2018	Germany	2015/2016	✓		✓			✓		
(Prajapati and Mahajan, 2021)	2020	IEEE 24-bus model	N/A	✓					✓	✓	
(Pantoš, 2020)	2020	IEEE 39-bus model	N/A	✓					✓		
(Diop, 2020)	2020	CWE	N/A	✓				✓			



## 1.2 MARKET DESIGN AND SYSTEM OPERATION: AN INTERNATIONAL OVERVIEW

We showed in the previous section that an evolution of bidding zones can be envisaged both as a means to enhance short-term operating conditions and as a attempts to adapt the market design to the physical evolution of the European power system.

In this section, we further explore the links between system operation and market design through **an overview of major international power systems from North America, Europe and Australia**. Based on these real-life examples, we first elaborate a classification of fundamental market design alternatives. We then discuss the physical implementation of these systems in terms of grid deployment and generation fleet in relation to the demographics of the considered regions. Through this comparative study, we therefore provide a perspective on the **short- and long-term implications of a market design change**.

### 1.2.1 A Classification of Main Market Design Options

Although access to electricity is relatively widespread across the globe, it is more uncommon to encounter large-scale transmission in combination to competitive wholesale electricity markets. In fact, the development of large-scale grid and market infrastructures is subject to stable political and socio-economic situations on a long-term basis in order to secure massive public investments. A detailed description of these prerequisites is available in (Rudnick and Velasquez, 2018).

For this work, we therefore selected our power system panel from developed countries, based on their diversity of market designs and generation fleets. Nonetheless, **continental Europe alone scales up any other interconnected system in the world in terms of population served and annual generation**, which leaves limited room for comparison. A broader case study exploring the links between market design and statistical characterization of wholesale electricity prices, which includes smaller systems in developing countries – is nonetheless available in (Mayer and Trück, 2018).

We first focused on **examples from North America**, and quite naturally included the **PJM Interconnection** (PJM)(PJM Interconnection LLC, 2022) and **California Independent System Operator** (CAISO) (California ISO, 2022). In particular, these are two major examples for the **use of nodal pricing** and are regularly compared to European zonal pricing. This is notably the case when Holmberg and Lazarczyk compare the performance of congestion management under nodal and zonal pricing schemes in (Holmberg and Lazarczyk, 2015). Both PJM and CAISO are located in the United States. In particular, the PJM perimeter covers thirteen states, historically including Pennsylvania, New Jersey and Maryland. Both received the status of independent system operator (ISO) based on pre-existing power pools, respectively in 1997 and 2008, and adopted locational marginal prices (LMPs) shortly after.

On the other hand, Canadian systems tend to rely on **province-wide uniform prices** that are therefore more related to zonal pricing. We therefore decided to integrate **Ontario's Independent Electricity System Operator** (IESO)(IESO, 2022b) in our analysis, as it corresponds to the most populated province. IESO was created in 1998 based on former public monopoly Ontario Hydro. All three studied North American systems are part of broader interconnected areas – which nonetheless does not imply coherent market design. PJM and the Ontario IESO are part of the Eastern Interconnection, which includes the Eastern part of the North American continent. CAISO is quite consistently part of the Western Interconnection.

As another international example, **Australia's National Electricity Market (NEM)** is another international instance for **zonal pricing**. Operated by the Australian Energy Market Operator (AEMO) (Australian Energy Market Operator (AEMO), 2022), it covers five bidding zones that coincide with the states of New South Wales, Queensland, South Australia, Victoria and Tasmania, as well as the Australian Capital Territory. The NEM was created in 1998 in alignment with the worldwide liberalization trend of the power industry.

The **European Power System** (ENTSO-E, 2022b) is the broadest example of **zonal market coupling** on the international scene. From a frequency regulation point of view, it is structured around five

synchronous areas: Continental Europe, the Nordic Countries, the Baltic Countries, United Kingdom and Ireland. In this analysis, we focus on Continental Europe and the EPEX Spot market operator (EPEX Spot, 2022), but we also integrate highlights from the Nordics area (NordPool (NordPool, 2022)) and Italy (Gestore dei Mercati Energetici – GME (GME, no date)). Both regions are distinguished by subnational pricing areas. Nonetheless, as opposed to the 2011 creation of clearly distinct bidding zones in the Nordics (Makkonen and Viljainen, 2012), Italy still has a **single national price (PUN)** (ENTSO-E, 2018b). This corresponds to the price perceived by consumers, storage units and used for the coupling with foreign neighbouring bidding zones. On the other hand, producers are subject to regional prices that may differ in the presence of congestion. More details on the Italian market processes can be found in the work of Ardian (Ardian, 2017).

From a general perspective, **a structural difference between European and other power system examples regards the relation between market and transmission system operation.** Outside of Europe, power system operation tends to rely on single entities monitoring both grid and market activities, which are called *independent system operators* (ISO). This opposes the European framework with separate *transmission system operator* (TSO) and *power exchange*. This distinction nonetheless admits a vast array of nuances, notably regarding the propriety of grid infrastructures, as detailed in (Chawla, 2013).

Our classification of the general market design of the mentioned power systems is presented in Figure 1.7. Many contributions addressing general market design classifications and specific dichotomies can be found in the literature. The presented distinctions are coherent with the concepts introduced in the works of Wilson (Wilson, 2002), Ventosa et al. (Ventosa, Linares and Pérez-Arriaga, 2013) and Mayer and Trück (Mayer and Trück, 2018).

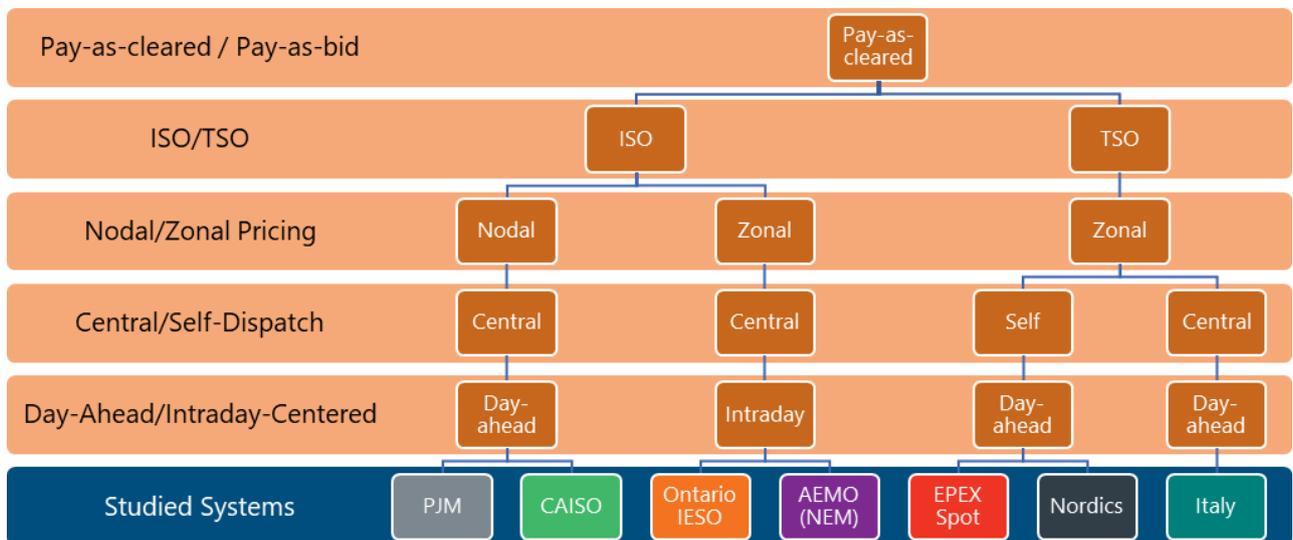


Figure 1.7: Market Design Classification of Selected Power Systems.

The following observations can be made over the considered power systems:

- **Pay-as-cleared v. Pay-as-bid pricing:** all considered systems rely on pay-as-cleared pricing in their spot markets, as opposed to pay-as bid. Under pay-as-cleared conditions, market participants remunerated based on the price obtained at market clearing, and not only for the value of their bid. Pay-as-bid characteristics can nonetheless be found, notably for the remuneration of redispatch actions in Europe.
- **ISO v. TSO:** non-European examples have a single entity in charge of market and system operation called *independent system operator* (ISO), as opposed to European power exchanges and TSOs.
- **Nodal v. Zonal Pricing:** PJM and CAISO rely on locational marginal prices that reflect both generation costs and grid constraints, as opposed to zonal spot prices. In the case of Ontario, the Hourly Ontario Energy Price averages several local prices,

which differs from the zonal merit-order market clearing presented in the previous section. More details on the computation of locational marginal prices are provided in Chapter 3.

- **Central v. Self-Dispatch:** under self-dispatch conditions, producers are free to dispatch their own accepted bids, while central-dispatch implies asset-specific orders by the market operator. This distinction fundamentally impacts bid format regarding the management of non-linear generation costs. In particular, central dispatch allows the submission of **multi-part offers** through which market participants can specify detailed costs as a function of the contracted energy volumes – which notably reflects generator start costs. Under self-dispatch bidding conditions, this is managed through **combinatorial auctions** that conditionally apply on consecutive market intervals.
- **Day-Ahead v. Intraday-Centered:** although all systems allow market players to propose bids on a day-ahead base, this does not always lead to an extensive planning of the dispatch. In the case of Ontario and the Australian NEM, day-ahead dispatch is thus a mere registration procedure directed at the most strategic units (IESO, 2014; Australian Energy Market Operator, 2019). On the contrary, day-ahead spot prices tend to be the reference

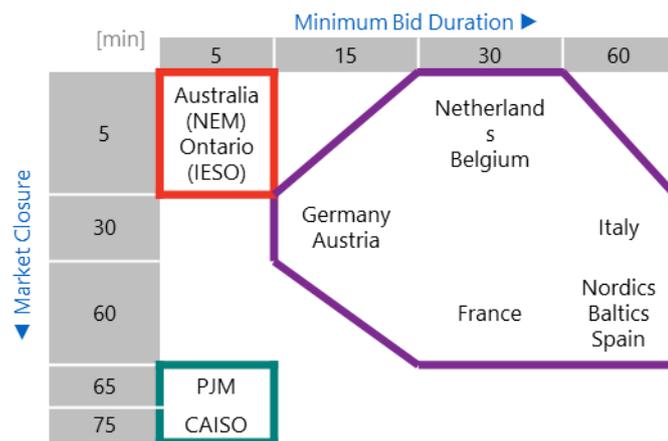


Figure 1.8: Market Chronology of the Selected Power Systems

spot price in other systems, with a strong day-ahead concentration of market liquidity (Mayer and Trück, 2018).

**Interestingly, the proximity of specific market designs is reflected in the temporality of market processes.** Figure 1.8 represents the minimum bid duration and time of market closure – i.e. the time interval where market participants are no longer allowed to propose and modify bids in anticipation to the time of dispatch. European countries show heterogeneity in market chronology, even though they are on their way to a common objective of a 15-minute minimal bid duration (XBID, 2018). On the one hand, IESO and the NEM are very close to real-time market clearing conditions, in accordance with their mainly intraday market design.

On the other hand, PJM and CAISO tend to rely on more anticipated market closure. As detailed by Ahlqvist and Holmberg in their comparative study on central and self-dispatch systems (Ahlqvist, Holmberg and Tangerås, 2019), **nodal systems using central-dispatch are more computationally demanding when it comes to dispatch optimization.** This creates both a lack of transparency regarding clearing processes and of short-term flexibility concerning the integration of emerging technologies on the supply and demand side.

Furthermore, Ahlqvist and Holmberg argue that European markets can mainly be improved by **strengthening the consideration for grid constraints**, which seems to advocate for bidding zone revision. This preliminary exploration of market designs therefore suggests that while market designs significantly affect short-term operational conditions, there is no clear stand-out regarding longer-term evolutions of electric industries around the world. In that sense, and as a call-back to ENTSO-E's Vision 2030 (ENTSO-E, 2019c), **bidding zone revision mostly makes sense if zone amendments are articulated with a long-term picture for the European power system.**

## 1.2.2 Behind the Market Design: Contrasted Operating Realities

This preliminary classification of market design highlight strong contrasts between international examples as well as clear similarities between markets. **Structurally different operating conditions nonetheless lay behind.**

Table 1.III presents the population served by each power system. In the first place, the European power system stands out for **providing electricity to hundred million persons over a continent.** Under this perspective, PJM with the second most populated perimeter serves less individual consumers than France.

Two demographic profiles nonetheless emerge from Figure 1.9. Europe, PJM and California are quite densely populated with around one hundred inhabitants per squared kilometer. This opposes power systems with more spatially distributed population, here represented by Ontario and Australia. These first observations clearly sets the European system apart from other zonal systems, and generally highlights **how unprecedented the deployment of a coherent market design over a full continent is.**

*Table 1.III: Population Served by System*

System	PJM	CAISO	IESO	NEM	EU
<b>Population served (.10<sup>6</sup> pers.)</b>	65	32	15	22	530

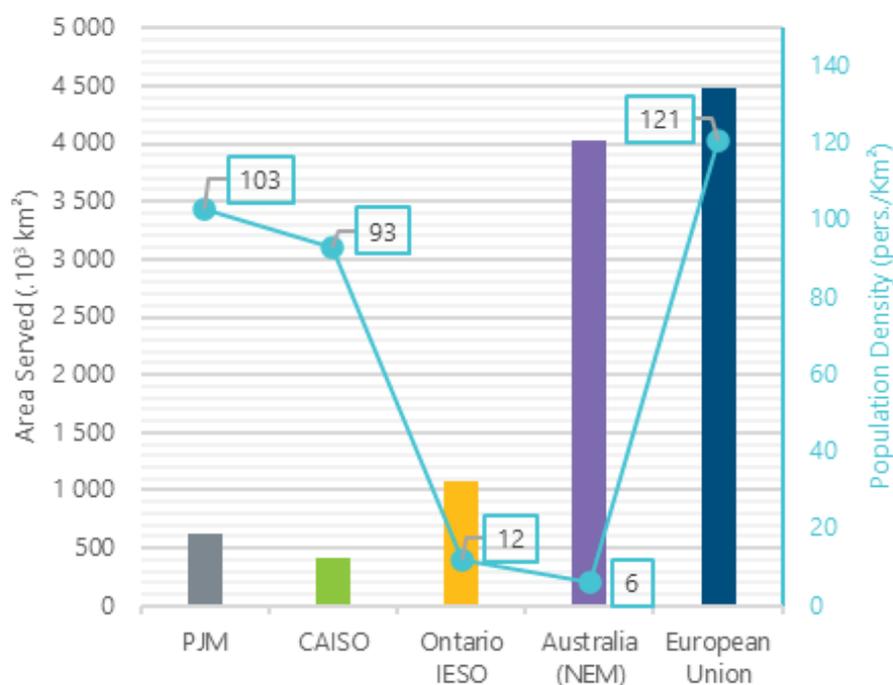


Figure 1.9: Area Served and Population Density by System.

This distinction between spatially dense and spread-out systems also translates in Figure 1.10, which features the total length of the operated transmission circuit as well as the corresponding spatial density of grid infrastructure. In particular, Ontario and Australia present a more scattered spatial covering of the served territory, with less than 5 kilometers of line within a hundred squared kilometers.

More surprisingly, PJM stands out with a particularly dense spatial density of the transmission infrastructure. This is clarified by Figure 1.11, which shows that PJM operates a relatively high proportion of lines under 150 kV, a priori imposing a superior circuit length for an equivalent transmission capacity as CAISO or European countries. The grid meshing indicator presented in Figure 1.11, which corresponds to the number of substations for a hundred kilometers of transmission line, also tends to indicate that **transmission systems in Ontario and Australia are more radially deployed, which we attribute to the spatially scattered served population.**

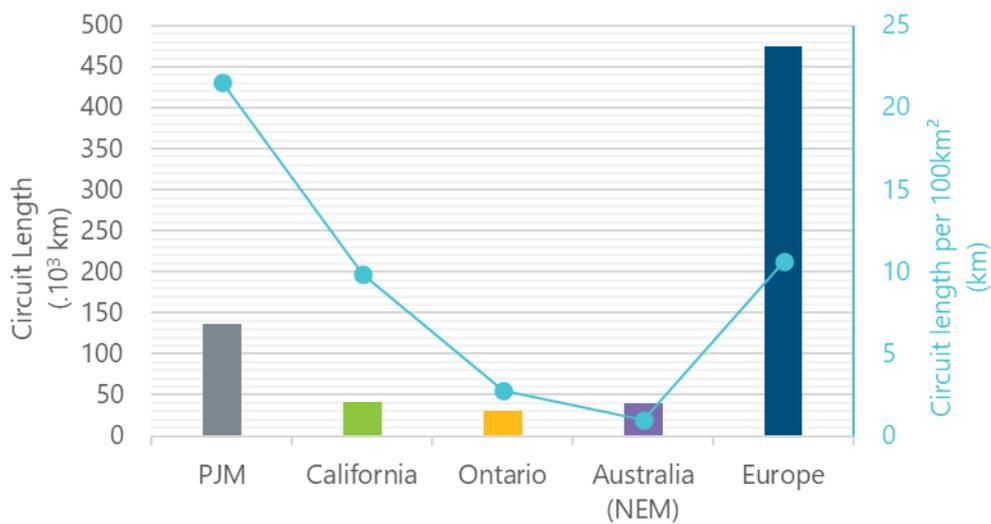


Figure 1.10: Transmission Circuit Length and Grid Spatial Density by System .

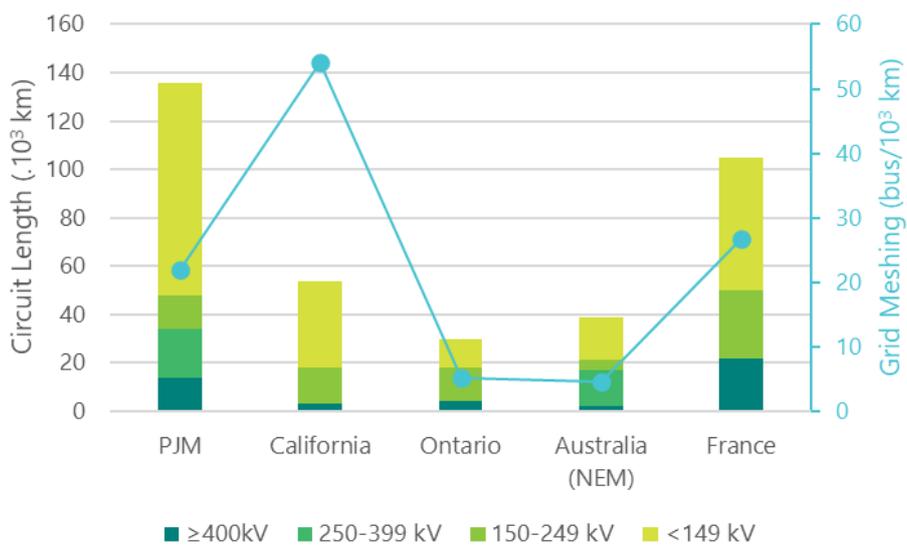


Figure 1.11: Distribution of Voltage Levels and Transmission Grid Meshing by System.

Sources for Figures 1.10 and 1.11 include (Australian Renewable Energy Agency, no date; California Energy Commission, no date; Open Data Réseaux Énergies, no date; PJM Interconnection, no date; ENTSO-E, 2019b; IESO, 2022c). The data from Table 1.IV and Figures 12-14 feature annualized indicators from reference years prior to the global Covid-19 outbreak. These were generally taken from annual market

reports, including (Australian Energy Regulator, 2018; California ISO, 2019; Commission de Régulation de l'Énergie, 2019; IESO, 2019, 2022a; Monitoring Analytics LLC, 2020; ENTSO-E, 2022a).

Results from Table 1.IV show that PJM stands out by the overall dimensioning of its total generation capacity, with demand hitting up to 80% of the installed capacity in 2019 and 51% on average – while other systems present a peak demand that does not exceed 60% of the installed capacity. This is explained by the very low representation of renewable capacities in the generation fleet – which includes wind, solar, hydro, geothermal and biomass generating assets. **In particular, these renewable technologies are currently associated with relatively low capacity factors, which results in higher capacity requirements in order to secure supply adequacy.**

On the other hand, the average Californian electricity demand only reaches 32% of the installed capacity, while this figure is closer to 40% for Ontario, Australia and the European Union, where the installed renewable capacity is similar. This can be explained by looking at the generation mixes presented in Figure 1.12 – which also features net imports and net exports since they are normalized according to the annual demand. In fact, California relies on an exceptional penetration of solar energy, associated with significantly lower capacity factors than wind power for example. **In contrast with PJM, the satisfaction of the Californian demand therefore requires higher installed generation capacity overall.**

Figure 1.12 also illustrates fundamental differences regarding the integration of low-carbon energy sources, which is directly reflected by the greenhouse gas emission reported in Figure 1.13 (Sources : (Clean Energy Council, no date; Monitoring Analytics LLC, 2020; California Air Resources Board, 2022; European Environment Agency, 2022; IESO, 2022a)). While both rely preeminently on thermal sources, **the Australian carbon intensity (i.e. emission per megawatt-hour) is significantly higher than PJM's due to the massive use of coal power plants.** On the other hand, the penetration of wind, hydro and nuclear power in Ontario's energy mix makes it exceptionally low-carbon.

Table 1.IV: Selected Data on System Capacities and Demand.

	PJM 2019	CAISO 2018	IESO 2019	NEM 2018-19	EU 2019
<b>Installed Capacity (GW)</b>	185	80.3	38.6	55.3	1002
Of which renewable sources (%)	8%	45%	37%	36%	49%
<b>Average Demand (GW)</b>	95	26	15	23	414
As a % of installed capacity	51%	32%	40%	42%	41%
<b>Annual Peak Demand (GW)</b>	148	46.4	21.8	32.5	589
As a % of installed capacity	80%	58%	56%	59%	59%

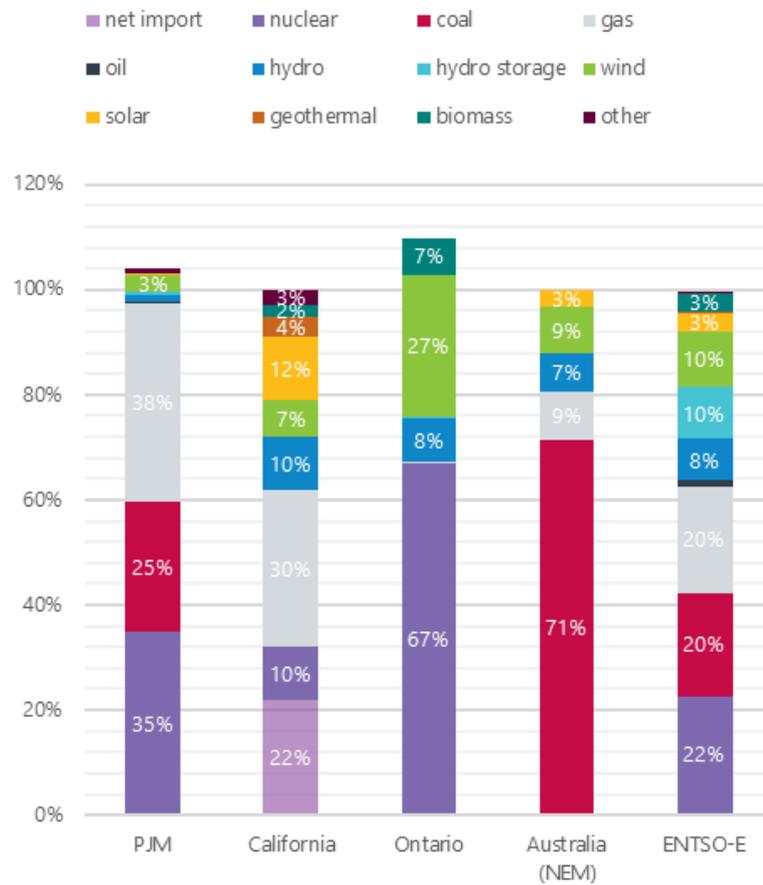


Figure 1.12: Generation Mix as a Percentage of Annual Consumption  
- Including External Exchanges.

We therefore observe that power systems with very similar market designs, like Ontario and the Australian NEM or PJM and California, may be at very different stages regarding global decarbonation objectives. In other words, **on a short-term perspective, there is no clear evidence that low-carbon energy mixes are more or less compatible with currently observed market designs.**

This observation is confirmed by Figure 1.14, which presents overall system costs calculated based of energy and transmission costs reported by ISOs (Australian Energy Regulator, 2018; California ISO, 2019; IESO, 2019; Monitoring Analytics LLC, 2020) as well as generation data (ENTSO-E, 2022a) and transmission tariffs (ENTSO-E, 2019a) for a selection of European countries. In particular, systems with similar market designs, for example zonal pricing in Ontario, Australia and European countries, may present heterogeneous system costs per megawatt-hour, with no clear trend regarding the penetration of intermittent renewable sources.

On a short-term perspective, this international overview therefore tends to show that the economic and environmental performance of power systems is **highly determined by pre-existing conditions regarding generation fleets, grid deployment and demographics.** In that sense, the observed market designs are reflective of a regional context and therefore not fully extrapolable to the operation of other systems. From the perspective of bidding zone revision, this tends to advocate for **market designs that do not only target short-term operational benefits but also secure both consistency with historical system deployment and sustainable long-term dynamics for generation and grid investments.**



Figure 1.13: Annual GHG Emission by System.

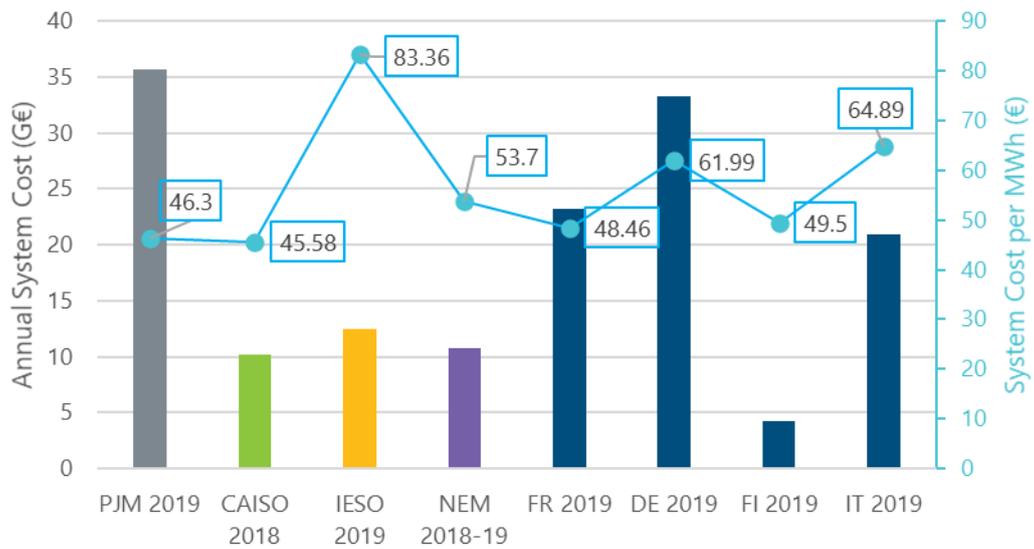


Figure 1.14: Annual System Costs (Generation + Transmission) by System.



## 1.3 REVISING BIDDING ZONES: PREVIOUS EFFORTS, CONCERNS AND EXPECTATIONS

As mentioned in the introduction of this chapter, European bidding zones has been subject to several institutional review process following the 2015 enforcement of the “Capacity Allocation – Congestion Management” network code (European Commission, 2015).

In this section, we introduce the reference Pan-European efforts regarding the evaluation of the current zone configuration and the elaboration of candidate alternative delineations. We present the main outcomes to this date and highlight the main evolutions in review processes over time.

We then complement this analysis with a review of the literature addressing bidding zone revision, market splitting and more generally market design transition in order to extract key academic expectations and concerns.

**We therefore argue for a multi-horizon, multi-dimensional analysis of the evolution of European bidding zones for wholesale electricity markets**, in a perspective that articulates system operation, market dynamics and short- to long-term objectives for the power system.

### 1.3.1 The Bidding Zone Review Initiatives

Figure 1.15 introduces a timeline of the main publications related to the evolution of European bidding zones, with a focus on the European Commission, the European Union Agency for the Cooperation of Energy Regulators (ACER) and the European Network of Transmission System Operators for Electricity (ENTSO-E).

In particular, two fundamental legislations come into play: the 2015 network code establishing a guideline on capacity allocation and congestion management (European Commission, 2015) and the 2019 “Clean Energy for all Europeans” package (European Commission, 2019).

On the one hand, the CACM network code was preceded by two assessments of the bidding zone configurations: a technical report addressing congestion management from ENTSO-E (ENTSO-E, 2014), and a market report by ACER (ACER, 2014).

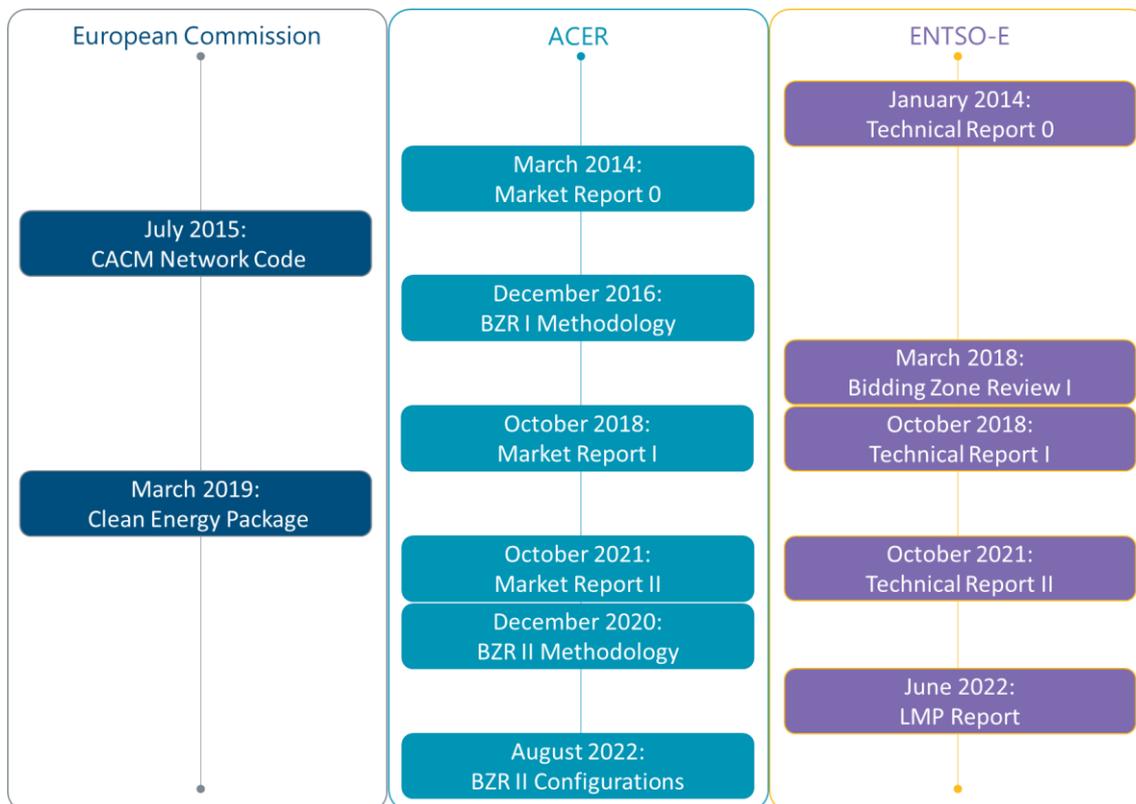


Figure 1.15: A Timeline of Main Institutional Publications - Bidding Zone Review.

The CACM network code notably established the periodic execution of both exercises from ENTSO-E and ACER on a triennial basis, which resulted in the 2018 and 2021 editions of ENTSO-E’s Technical Report (ENTSO-E, 2018a; Réseau de Transport d’Électricité, 2021) and an update of ACER’s market report within the 2017 and 2020 Market Monitoring Reports (ACER, 2021a, 2022b).

**This legislation also provided a grid of nineteen relevant indicators regarding the evaluation of the bidding zone configuration,** which were sorted into three main categories: “Network Security”, “Market Efficiency” and “Stability and Robustness of Bidding Zones”.

A more detailed analysis of this evaluation grid is provided in the introduction of Chapter 4. The network code also gave the impulsion for ACER's decision regarding the First Edition of the Bidding Zone Review, which was conducted by ENTSO-E and delivered in the beginning of 2018 (ENTSO-E, 2018b).

On the other hand, the 2019 Clean Energy Package (European Commission, 2019) introduced two regulatory staples. First, it introduced the 70% minimum threshold regarding the share of the physical capacity of critical branches that must be made available for commercial exchanges. An illustration of this requirement, referred to as CEP70, is presented on Figure 1.16. A more elaborate definition of loop flows is notably available in the 2014 ACER market report on bidding zones (ACER, 2014).

The enforcement of this criteria on January 1<sup>st</sup>, 2020 led to multiple derogations and initiated multi-year action plans in most of the member states, as described in ENTSO-E's 2021 Technical Report (ENTSO-E, 2021a). From a short-term perspective, and in the absence of market design change or further system developments, the enforcement of this criteria mostly leads to **allowing the violation of  $F_{max}$  in the capacity calculation process while planning costly corrective measures to restore the technical feasibility of transactions**. This is also represented on Figure 1.16.

Second, the Clean Energy Package and the associated Electricity regulation introduced the notion of structural congestion, defined as frequent, geographically stable constraints that affect cross-zonal capacities. It therefore states that the delineation of bidding zones should be aligned with the map of structural congestions, which led to the ACER Decision of a methodology initiating the second Bidding Zone Review process in December 2020 (ACER, 2020a)

**The emergence of institutional discussions over an evolution of bidding zones therefore resulted in recurrent evaluation exercises**, which we will discuss in the remainder of this paragraph.

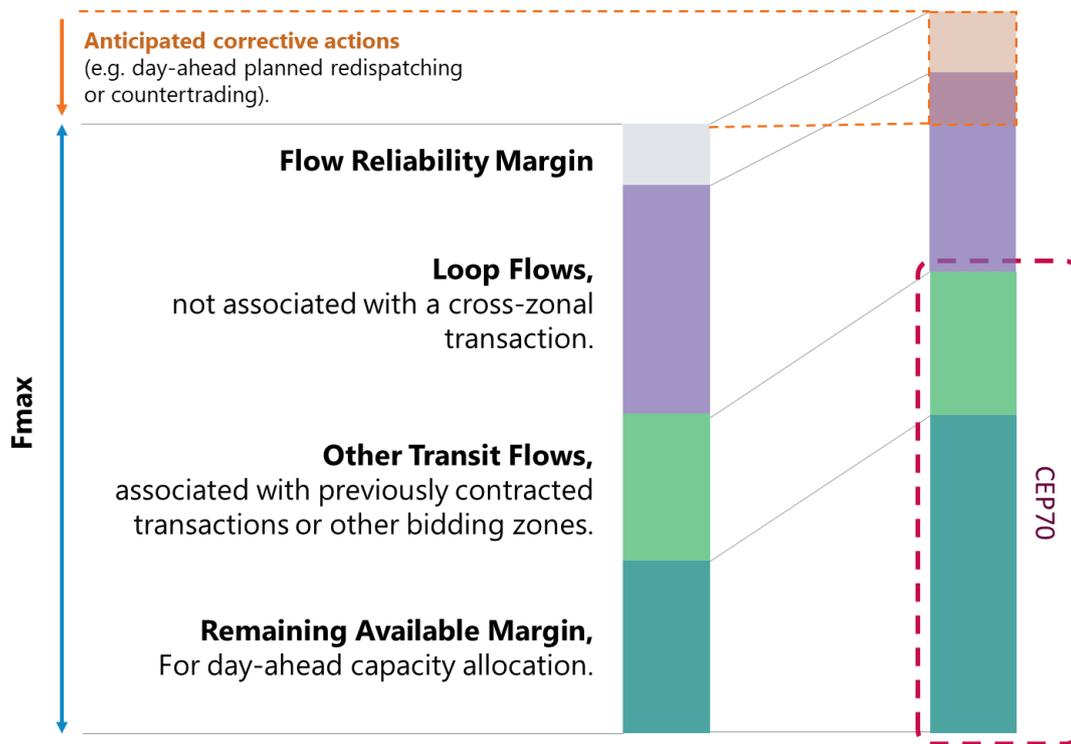


Figure 1.16: Illustration of the CEP70 Criteria for a Specific Critical Network Element.

In this series of institutional assessment, ACER's market monitoring reports are relatively concise. The 2014 edition provided an analysis of historical market data to quantify the impact of interconnection on zonal liquidity. On the other hand, the 2017 and 2020 editions report the costs of remedial actions per country, with an evaluation of compliance to the CEP70 criteria in the latter.

This is therefore relatively redundant with ENTSO-E's latest technical report for the 2018-2020 period (ENTSO-E, 2021a), which features analysis of congestion maps with the associated frequencies, detailed congestion costs and revenues and a review of the implementation of the CEP 70 requirement with the associated derogations and action plans. Interestingly, the covered three-year period cumulates the 2018 split of the AT-DE bidding zone, the 2020 enforcement of the CEP70 criteria and the 2020 Covid-19 outbreak. This locally affected specific bidding zones, including Austria which saw its congestion incomes increase after the AT/DE split then decrease in 2020 due to new demand dynamics of the ongoing pandemic.

From a Pan-European perspective, the report notably notes that “In the timeframe ‘Capacity calculation for the purpose of day-ahead capacity allocation’, reported congestions with a relative high frequency are generally at bidding zone borders or in their direct vicinity.” **This suggests that the current zone configuration was mostly aligned with structural congestions reported within the 2018-2020 period** – which does not exclude operational repercussions from less frequent congestions.

This observation nonetheless resonates with the main findings of the First Edition of the Bidding Zone Review (ENTSO-E, 2018b). As a matter of fact, this exercise considered two sets of alternative zone configurations.

- On the one hand, clustering methods were used based on estimations of nodal prices for a model of continental Europe. None of the resulting zone configurations were retained, which was justified by modeling assumptions that gave a disproportionate impact to non-frequent constraints on the 220 kV grid. This, in articulation with the 2021 technical report, **therefore questions the feasibility of basing an alternative on the sole identification of structural congestions.**
- On the other hand, the first Bidding Zone Review examined expert-based zone delineations that were manually elaborated by European transmission system operators. The CACM evaluation grid was therefore applied to a DE/AT split scenario, two “Big Country Split” configurations, which featured different split patterns for the biggest bidding zones, and a “Small Country Merge” delineation, which relied on multiple zone mergers. Nonetheless, the mostly qualitative evaluation of the CACM criteria **did not result in a consensus over a specific alternative zone delineation.**

The Bidding Zone Review methodology was therefore significantly updated in the 2020 ACER decision (ACER, 2020a). This second edition focuses on two bidding zone review regions, namely Continental Europe and the Nordics. The corresponding transmission system opera-

tors were asked to conduct extensive pan-European simulations in order to compute nodal prices for a 2025 horizon based on updated historical data. This time, the simulation chain was enhanced with extensive sensitivity analysis notably including a focus on topological actions – which were mostly disregarded in the 2018 edition. The results of this process were presented in an ENTSO-E report from June 2022 (ENTSO-E, 2022d), notably featuring temporal and spatial analysis of the variability of nodal prices for the concerned bidding zones.

As detailed in a 2021 ACER webinar (ACER, 2021b), bidding zones were then considered separately regarding two indicators: nodal prices differentials on the one hand, which highlight the presence of congestions, and the volumes of loop flows on the other hand, which refers to the CEP70 criterion. Clustering methods were applied iteratively to the less performant bidding zones in order to envisage different levels of splitting. **This second bidding zone review therefore restrains zone amendments to combinations of national splits.**

This resulted in the August 2022 ACER “Decision on the alternative bidding zone configurations to be considered in the bidding zone review process” (ACER, 2022c). Among the eight delineations selected for Continental Europe, seven correspond to the split of a single country: four for Germany, and respectively one for France, Italy and the Netherlands. The single configuration affecting several countries includes joint splits of Germany and the Netherlands. The two configurations selected for the Nordics feature a split of Sweden respectively in three and four zones – while four bidding zones are already implemented in Sweden.

While the considered splits tend to significantly reduce nodal price differentials, the zone amendments envisaged for France, Italy and the Netherlands nonetheless fail to reduce the loop flow indicator by more than 1% compared to the status quo – an increase is even observed in some cases. **One can also note that these indicators are hard to adapt conjointly to separate bidding zones – which might have made it difficult to integrate more multinational combinations of zone splittings.**

According to these results, only a few countries in Continental Europe seem to offer significant potential for loop flow reduction and improved congestion management, among which Germany, France, Italy and the Netherlands. In particular, the highest nodal price spreads tend to concern the North of Continental Europe, and are easy to link with the intensive pace of RES deployment in this area.

An extensive assessment of the retained configurations is nonetheless expected for the end of 2022, including an evaluation of the CACM criteria. While this first overview does not presume of the final assessment results, **the concentration of highest operational potentials in very specific geographic areas highlight how difficult it is to build a truly pan-European perspective on the evolution of bidding zones.**

### 1.3.2 Academic Concerns and Expectations on Bidding Zone Revision

The elaboration of performant bidding zone delineations is also a recurrent research interest of the past decade. Table 1.V presents a short review of academic contributions on the topic, with a simple classification of the underlying research focuses.

**In particular, we chose to highlight three evaluation axes in the reviewed contributions : system operation**, which mostly has to do with congestion management and nodal price spreads, **market dynamics**, for contributions that address impact of zone revision on generation dynamics or price formation, and **time robustness**, to highlight case studies where multiple time horizons are considered. More examples are detailed below, an a more extensive review of the related models and methodologies will be explored in Chapters 2 to 4.

Table 1.V: A Literature Review on Bidding Zone Revision.

Ref.	Year of Publication	Studied System	Period Studied	Main Focus		
				System Operation	Market Dynamics	Time Robustness
(Burstedde, 2012)	2012	Central Western Europe	2015/2020	✓	✓	✓
(Raofat and Eghtedarpour, 2012)	2018	IEEE 118-bus test system	N/A	✓		
(Breuer and Moser, 2014)	2014	Continental Europe	2016/2018	✓	✓	✓
(Van Den Bergh <i>et al.</i> , 2016)	2016	Continental Europe	2013	✓	✓	
(Egerer, Weibezahn and Hermann, 2016)	2016	Germany	2012/2015	✓	✓	
(Plancke, De Jonghe and Belmans, 2016)	2016	Germany	2020		✓	
(Grimm, Martin, Weibelzahl, <i>et al.</i> , 2016)	2016	Three-node network	N/A		✓	
(Marinho <i>et al.</i> , 2017b)	2017	Continental Europe	2013	✓		
(Felling and Weber, 2018)	2018	Central Western Europe	2020	✓		✓
(Grimm <i>et al.</i> , 2017)	2019	< 30-node test systems	N/A		✓	
(Kiran, Abhyankar and Panigrahi, 2019)	2019	193-bus Western Regional Grid of India	2010	✓		
(Ambrosius <i>et al.</i> , 2020)	2020	Two-node example	N/A		✓	
(Colella <i>et al.</i> , 2021)	2021	Italy	2018	✓		
(Schönheit <i>et al.</i> , 2021)	2021	Three-zone test network	N/A	✓		
(Blachnik, Wawrzyniak and Jakubek, 2021)	2021	IEEE 39-bus test system	N/A	✓		

As expected, **a majority of contributions feature system operation concerns**. Most approaches tend to quantify the impact of a bidding zone revision on congestion management through conventional indicators like redispatch costs and volumes ((Burstedde, 2012; Breuer

and Moser, 2014; Egerer, Weibezahn and Hermann, 2016; Marinho *et al.*, 2017b; Schönheit *et al.*, 2021)) or line congestion ((Raoufat and Eghtedarpour, 2012; Van Den Bergh *et al.*, 2016; Schönheit *et al.*, 2021)). Nonetheless, this also includes contributions focusing on nodal price differentials ((Felling and Weber, 2018; Kiran, Abhyankar and Panigrahi, 2019; Blachnik, Wawrzyniak and Jakubek, 2021; Colella *et al.*, 2021; Schönheit *et al.*, 2021)), insofar as they are directly reflective of grid constraints.

This observation clearly illustrates the expected link between the configuration of bidding zones over a given system and a general improvement of operating conditions, notably regarding congestion management. The performance of system operation therefore becomes both a criteria to generate alternative zone configurations and a general evaluation criteria.

On the other hand, several contributions address **the impact of zone reconfiguration of market dynamics**. In a number of research works, this is mostly apprehended through the impact on generation costs and volumes (Burstedde, 2012; Breuer and Moser, 2014), with recurrent analyses of the market penetration of various renewable and thermal energy sources (Egerer, Weibezahn and Hermann, 2016; Van Den Bergh *et al.*, 2016). The overall impact of bidding zone revision on zonal prices is also regularly addressed (Burstedde, 2012; Egerer, Weibezahn and Hermann, 2016). In addition, Plancke *et al.* (Plancke, De Jonghe and Belmans, 2016) include an evaluation of cross-zonal exchanges and consumer surplus, as well as price duration curves. Other contributions manage to propose more dynamic analyses of market outcomes, yet they tend to involve computationally challenging methodologies that are applied to relatively small test systems.

The work of Grimm *et al.* is representative of this trend with the analysis of the long-term effects of market splitting in (Grimm, Martin, Weibelzahl, *et al.*, 2016), which notably addresses the detrimental impact of cross-zonal capacity approximation on the welfare-optimality of investment signals. The impact on investment signals of the anticipation of an uncertain bidding zone reconfiguration by market participants is also addressed in (Ambrosius *et al.*, 2020). Once again, this market dimension is also envisaged both as an evaluation

axis and as a criteria for designing alternative zone delineations. For example, a mixed-integer multilevel method for designing welfare-optimal bidding zones is presented in (Grimm *et al.*, 2017).

However, we note that the reviewed contributions tend to focus on the immediate impacts of a bidding zone revision, with little interest for the robustness of the observed operational and market performances. **Some authors nonetheless include several time horizons or various system trajectories in their case studies.** In particular, Burstedde (Burstedde, 2012) integrates both 2015 and 2020 dispatch scenarios, and obtains different values for the optimal number of zones. Breuer and Moser (Breuer and Moser, 2014) use 2018 data to analyse the sensitivity of their 2016 case study. Felling *et al.* (Felling and Weber, 2018) nonetheless propose a more advanced contribution by proposing a zone delineation method that is robust to different system trajectories regarding renewable penetration, demand, grid development and exogeneous economic conditions.

While a strong focus is given to efficient system operation and congestion management, bidding zone revision as an academic research topic also raises concerns regarding the impacts on zonal generation and the resulting price and investment dynamics. Methodologies therefore emerge to secure a trade-off between system operation and market efficiency. In more uncommon cases, this is also associated with a concern on zone robustness to future evolutions of the considered system. **Our review nonetheless suggests a lack of contributions that combine system operation, market efficiency and zone robustness from a large-scale continental or pan-European perspective.**

Finally, neither the literature nor previously introduced institutional works fully address the transition costs associated with a bidding zone revision, which is nonetheless a CACM criteria. The First Edition of the Bidding Zone Review (ENTSO-E, 2018b) proves quite unable to compare the transition costs induced by the considered reconfiguration scenarios, acknowledging a difficult assessment due to multiple impacts for governmental institutions, energy producers or even bank and trading companies. In this context, the authors of (Bemš *et al.*, 2016) advocate for a five-year evaluation period of transition

costs, arguing that one-time costs may be deceptive because of the possible implementation inertia.

Even from a general perspective, very few exercises are available to anticipate the transition costs associated with a change of market design. In (Climate Policy Initiative, 2011), Neuhoff and Boyd present a cost-benefit analysis of the transition from zonal to nodal pricing in specific regions of the United States. Even then, the situation is quite heterogeneous: while PJM seems to have reached significant cost savings, this is not the case for the Texan ISO ERCOT. In a recent publication from the Joint Research Center of the European Commission (Antonopoulos *et al.*, 2020), it is advanced that a European switch from zonal to nodal pricing would allow a reduction of operation costs by up to 4%. This nonetheless corresponds to the results of a 2013 publication featuring 2008 data and restrained to Continental Europe (Neuhoff *et al.*, 2013).

In addition, conventional simulation work proves inefficient for giving a realistic and up-to-date estimation of the transition costs associated with a given bidding zone revision. In particular, this estimation would notably include the valorization of a new legal and organizational design associated with variable compensation mechanisms.

Even though an extensive cost-benefit analysis seems therefore out of reach, our previous review suggests an opportunity to complement the existing literature **through an approach that combine system operation and market dynamics on a multi-horizon basis and for a large-scale model of the European power system.**



## KEY FINDINGS – CHAPTER 1

In this chapter, we put in perspective the role and impacts of a bidding zone revision in the European power system. Our analysis of the topic combines academic sources on congestion management, market design and bidding zone revision, technical documentation from major power systems in the world and main institutional productions regarding the Bidding Zone Review process. Complementary literature reviews involving relevant models, methodologies and indicators will also be conducted in the following chapters.

From a general point of view, we showed that the perspective of a bidding zone reconfiguration reflects both short-term operational objectives and broader aspirations regarding the long-term evolution of the power system. **However, the encountered institutional and academic exercises show how difficult it is to reconcile operational and market criteria over short- to long-term time horizons and while keeping a pan-European perspective.**

Moreover, our exploration of international examples demonstrates that the short-term performance of a given power system is highly dependent on its pre-existing physical implementation. This suggests that the validity of a specific market design should be evaluated regarding its **capacity to both favour relevant system dynamics in the long run and enhance existing resources, notably in terms of generation fleet and grid infrastructures.**

Bidding zone revision is therefore not an easy market design lever. While tempting and potentially very efficient on a short-term perspective, targeting **efficient zone amendments that support sustainable system trajectories in the long run requires particular attention to multidimensional and multi-horizon impacts.**

In the remainder of this work, we develop methods and analyses that illustrate the fundamental steps of the **design and evaluation of candidate delineations for European bidding zones**, through combining grid and market modelling frameworks. In Chapter 2, we review the related modelling frameworks and publicly available data, then introduce our main simulation chain. In Chapters 3 and 4, we

respectively address the automated design of alternative zone delineations and conduct an multidimensional and multi-horizon assessment of the resulting reconfiguration scenarios.

We thereby **characterize and quantify the main trade-offs regarding system operation and market dynamics on a short- to long term perspective.** We complement this main approach in Chapter 5, where we introduce a complementary simulation chain that allows an extended analysis of market dynamics and investment trajectories.

## 2 MODELLING APPROACHES TO THE PERFORMANCE OF BIDDING ZONE CONFIGURATIONS

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In this chapter, we address conventional modelling approaches generally involved in the study of bidding zone configurations, also discussing our needs regarding available data and models. After our review addressing market design transitions in Chapter 1, we therefore present our first efforts to set up a simulation chain for multi-dimensional, multi-horizon analysis.

As developed in Chapter 1, an evolution of European Bidding Zones is likely to impact both system operation and market dynamics, and eventually affect system dynamics in the long-run. This suggests a **need for detailed spatial and temporal modelling of the European Power System**, with a specific focus on the integration of grid constraints and multiple time horizons.

More generally, the ambition to combine grid- and market-oriented modelling approaches is a growing concern in both the academia and the industry. In a context of quick and spatially heterogeneous development of renewable energy sources, the consideration of emerging transmission constraint dynamics is pushing for sophisticated approaches that **combine characteristics from classical unit commitment and optimal power flow problems**.

On the one hand, some contributions tend to favour optimal power flow simulations that integrate detailed grid constraints, yet complement this approach with enhanced time representation. This can be found in the work of Felling and Weber (Felling and Weber, 2018), who run simulations for all hours of a full year. This is also the approach of European transmissions system operators in the most recent Bidding Zone Review process (ENTSO-E, 2022d), where clustering methods are deployed to extract dispatch scenarios representing three sets of eight representative weeks from the 1987-2016 period.

On the other hand, contributions that directly integrate grid constraints into dynamic system modelling are less common since **computationally more demanding**. In particular, they often rely on small test models with at most a few dozen nodes – 118 in (Bai *et al.*, 2015), 31 in (Alvarez, Marcovecchio and Aguirre, 2016), 30 in (Ma and Shahidehpour, 1998; Li *et al.*, 2019). Nonetheless, Tseng *et al.* (Tseng *et al.*

*al.*, 1999) manage to run a transmission constrained unit commitment over a model with 2,500 buses, and Isuru et al. with 2383 buses (Isuru et al., 2020). Fundamentally, the corresponding methods rely on advanced, multi-step solving processes, notably involving Benders decomposition (Ma and Shahidehpour, 1998; Bai et al., 2015; Isuru et al., 2020), binary artificial sheep algorithm (Li et al., 2019), Lagrangian relaxation (Tseng et al., 1999). In general, unit commitment problems are formalized as mixed-integer linear or nonlinear optimization problems, as pointed out by (Syranidis, Robinius and Stolten, 2018).

The literature nonetheless offers a reconciling option that consists in **conducting grid-oriented simulations** in the first place, **then performing relevant network reduction in order to work with simplified dynamic market models** (Li and Balakrishnan, 2016; Marinho, 2018). This avenue, which combines relative computational simplicity and model complementarity, **will be explored in the remainder of this work.**

The following sections are organized as follows. Section 2.1 provides a review of conventional modelling frameworks, with a focus on grid- and market-oriented simulations. Section 2.2 presents our benchmark of reference test systems as well as our effort to design our own 30-bus benchmark grid model. Finally, Section 2.3 focuses on available Pan-European models and data, then introduces the main static grid model that will be used in the remainder of this work.

## 2.1 A REVIEW OF CONVENTIONAL MODELLING FRAMEWORKS

In their review of control techniques for modelling power flows into transmission grids, Syranidis, Robinius and Stolten (Syranidis, Robinius and Stolten, 2018) identify a common problem formulation for power market simulation, called the Economic Dispatch problem. This fundamental framework consists in the allocation of generator outputs through minimizing total operational costs.

In this section, we discuss how both optimal power flow and unit commitment formalisms derive from this common formulation, and **the ways to combine them using the same input grid model**. We then discuss main avenues **to integrate medium- to long-term system dynamics in the simulation chain**.

### 2.1.1 Optimal Power Flow as a Grid-Oriented Modelling Framework

As mentioned in several contributions (Frank, Steponavice and Rebennack, 2012; Marinho *et al.*, 2017b), the optimal power flow (OPF) problem can be described through the conventional equations of a linear optimization problem. These are detailed in Equations (2.1)-(2.3) for a given dispatch interval  $t$ .

$$\min f(u, x) \quad (2.1)$$

Such that:

$$g(u, x) = 0 \quad (2.2)$$

$$h(u, x) \leq 0 \quad (2.3)$$

Where  $f$  is the scalar objective function, representing the sum of all marginal generation costs, vector functions  $g$  and  $h$  represent all inequality and equality constraints of the system (*e.g.* maximum generation outputs, line capacities, supply adequacy...), and vectors  $u$  and  $x$  respectively contain control (*e.g.* generator outputs) and state (*e.g.* line loads) variables.

In particular, a more specific OPF formulation using direct current (DC) approximation could be the one presented in Equations (2.4)-(2.10).

$$\min \sum_{g \in G^{\text{disp}}} c_g P_g + \sum_{g \in G^{\text{fatal}}} c^{\text{curt}} \cdot P_g^{\text{curt}} + \sum_{i=1}^{N_b} c^{\text{shed}} \cdot P_i^{\text{shed}} \quad (2.4)$$

Such that:

Supply-Demand Equilibrium:

$$\sum_{g \in G^{\text{disp}}} P_g + \sum_{g \in G^{\text{fatal}}} (\text{cap}_g \cdot \bar{P}_g - P_g^{\text{curt}}) = \sum_{i=1}^{N_b} (D_i - P_i^{\text{shed}}) \quad (2.5)$$

Generation Constraints:

$$P_g \leq \bar{P}_g ; \forall g \in G^{\text{disp}} \quad (2.6)$$

$$P_g^{\text{curt}} \leq \text{cap}_g \cdot \bar{P}_g ; \forall g \in G^{\text{fatal}} \quad (2.7)$$

Transmission Constraints:

$$|f_l| \leq \bar{f}_l ; \forall l \in L \quad (2.8)$$

$$f_l = \sum_{i=1}^{N_b} \text{PTDF}_{i,l} \cdot P_i^{\text{Inj}} ; \forall i \in \{1, \dots, N_b\}; \forall l \in L \quad (2.9)$$

$$P_i^{\text{Inj}} = \sum_{g \in G^{\text{disp}}} \delta_{i,g} P_g + \sum_{g \in G^{\text{fatal}}} \delta_{i,g} \cdot (\text{cap}_g \cdot \bar{P}_g - P_g^{\text{curt}}) - (D_i - P_i^{\text{shed}}); \forall i \in \{1, \dots, N_b\} \quad (2.10)$$

Where:

### SETS

- $G$  is the set of generators in the system;
- $G^{\text{disp}}$  is the subset of dispatchable generators in the system;
- $G^{\text{fatal}}$  is the subset of RES units in the system;
- $L$  is the set of lines.

### PARAMETERS

- $N_b$  is the number of buses in the grid;
- $\bar{P}_g$  is the maximum output of generator  $g$ ;
- $\bar{f}_l$  is the flow limit on line  $l$ ;
- $c_g$  is the variable cost of generator  $g$ ;
- $c^{\text{curt}}$  is the cost of RES curtailment;
- $c^{\text{shed}}$  is the cost of load shedding;
- $D_i$  is the electricity demand at node  $i$ ;
- $\text{cap}_g$  is the capacity factor of generator  $g$ ;
- $\text{PTDF}_{i,l}$  is the nodal power transfer distribution factor of node  $i$  on line  $l$ . Equals 0 if bus  $i$  is not connected to line  $l$ ;
- $\delta_{g,i}$  equals 1 if generator  $g$  is located at bus  $i$ , 0 if not.

### VARIABLES

- $P_g$  is the output of dispatchable generator  $g$ ;
- $f_l$  is the flow on line  $l$ ;
- $P_i^{\text{shed}}$  is the volume of load shedding at bus  $i$ ;
- $P_g^{\text{curt}}$  is the volume of curtailment of static generator  $g$ ;
- $P_i^{\text{Inj}}$  is the volume of injection at bus  $i$ .

**The transmission constraints presented in Equations (2.8)-(2.10) are characteristic of the direct current (DC) approximation**, as fully detailed in this article from Van den Bergh et al. (Van Den Bergh *et al.*, 2014). In particular, this formalism integrates both line capacities (cf.

Equation (2.8)) - that are derived from nominal rating - and the relation between line flows and nodal injections (cf. Equations (2.9) and (2.8)).

Van den Bergh et al. show that line flows can be deduced from the injection of one of the connected buses through a linear coefficient corresponding to a nodal power transfer distribution factor. This coefficient is shown to be derived from line reactances only, under the assumptions that line resistances are negligible compared to line reactances, that voltage profiles are flat and that voltage angles between connected buses are small. In addition, and as detailed in (Van Den Bergh *et al.*, 2014), these assumptions ensure that reactive power dynamics are negligible compared to active power flows in the system. More details on the different levels of approximation regarding static grid models are discussed in Section 2.3.1.

**In practice, DC-OPF formulations are quite hegemonic in the literature regarding bidding zone revisions** (Burstedde, 2012; Breuer and Moser, 2014; Marinho *et al.*, 2017b; Felling and Weber, 2018), **and more generally in contributions addressing congestion management in a European context** (Breuer *et al.*, 2011; Kunz and Zerrahn, 2015; Schermeyer, Vergara and Fichtner, 2018; Diop, 2020).

From a general perspective, the DC-OPF formulation allows a vast array of derivatives regarding the variables, objective functions and constraints involved. An extensive review of these formulations is presented in (Frank, Steponavice and Rebennack, 2012). Let us nonetheless mention the possibility to integrate environmental criteria, minimal generator outputs and additional transmission interface specifications.

Explicit outcomes of a DC-OPF simulation therefore include generator outputs  $P_g^*$ , and line flows  $f_l^*$ . More implicitly, **the solving also allows the computation of nodal prices, i.e. locational marginal prices (LMPs)**, defined as the shadow prices for relaxing the demand constraint at each node (Wilson, 2002). On a more straightforward note, the locational marginal price associated to a given node illustrates **the variation of total system marginal costs resulting from a one megawatt additional injection at this node**. LMPs therefore **reflect both generation marginal costs and grid**

## **constraints.**

In the context of this work, the use of optimal power flow simulations with DC approximation seems relevant as it allows **extensive analysis of grid constraints for a given market interval** while securing tractability over large-scale grid models. Robust and coherent input grid models as well as judicious scenarization with representative dispatch configurations are nonetheless essential, which will be discussed in the following sections.

### 2.1.2 Unit Commitment and the Simulation of Market Dynamics

As explored in the previous section, DC-OPF simulation is a relevant avenue for detailed analysis of the influence of network infrastructure on economic dispatch. Nonetheless, results are independent from the implemented bidding zone configuration – unless specific interface constraints are enforced – and are solely representative of the dispatch obtained after congestion-corrective actions.

In this work, the DC-OPF framework will therefore be involved in the design of congestion-compliant zone delineation scenarios rather than assessment efforts on candidate configurations. We consequently find ourselves in **need of a complementary framework to address the impact of possible bidding zone revisions on zonal dispatches** – and the corresponding zonal prices.

As detailed in the introduction of this chapter, the perspective of dynamic market simulations on a full grid-compliant model supposes intense modelling efforts, which can be considerably **relieved by network reduction**.

In (Marinho, 2018), Marinho identifies three steps to the network reduction process:

**Step 1:** Bus aggregation into clusters ;

**Step 2:** Modelling of links between clusters;

**Step 3:** Definition of links' maximal capacities.

In our case, **Step 1** coincides with the design of a candidate bidding

zone configuration, i.e. bus clusters coincide with the considered zones. Several options nonetheless coexist regarding the definition of congestion compliant market coupling, i.e. **Steps 2-3**. This aspect will be further discussed in Chapter 5.

General reviews of unit commitment formalisms and resolution techniques are available in the works of Montero, Bello and Reneses in (Montero, Bello and Reneses, 2022), Abdou and Tkiouat in (Abdou and Tkiouat, 2018) or Prasad Pradhi in (Padhy, 2004). While the general formulation of Equations (1)-(3), additional constraints regarding generation dynamics tend to involve integer variables. This is the case of constraints regarding start-up and shutdown costs, generation ramp limits or minimal outputs. Consequently, a vast majority of the unit commitment problems reviewed in (Padhy, 2004; Abdou and Tkiouat, 2018; Montero, Bello and Reneses, 2022) involve mixed-integer linear programming.

From an input data perspective, while optimal power flow simulation can be based over series of non-consecutive yet representative dispatch scenarios as in (Marinho *et al.*, 2017b), unit commitment justifies the use of input time series – i.e. series of consecutive dispatch scenarios regarding renewable generation, hydro availability, demand or any other time-dependent input data. Further details regarding the set up of a multi-zonal unit commitment model will be developed in Chapter 5.

Marinho *et al.* (Marinho *et al.*, 2017b) nonetheless introduce an **approximation method that spares the implementation of a full UC problem by further exploiting the DC-OPF results**. They thereby estimate the commitment of generators in zonal dispatches associated with their representative scenarios, subsequently using it to estimate the necessary redispatch measures.

For this purpose, let us suppose that we dispose of a reduced model as described in the beginning of this section. Let  $Z$  be the set of zones in the system. Let  $NEx_z$  be the net position of zone  $z$ , defined as the differential between outgoing and incoming power flows. In the reduced models, the knowledge of net positions is therefore sufficient to describe the contribution of all grid constraints to the zonal

dispatch. The residual demand of zone  $z$  therefore becomes:

$$ResD_z = \sum_{i=1}^{N_b} \gamma_{i,z} D_i - \sum_{g \in G^{fatal}} \beta_{g,z} \cdot (\text{cap}_g \cdot \bar{P}_g - P_g^{\text{curt}}) + NE x_z \quad (2.11)$$

Where  $\gamma_{i,z}$  equals 1 if bus  $i$  is in zone  $z$ , 0 if not, and  $\beta_{g,z}$  equals 1 if generator  $g$  is in zone  $z$ , 0 if not.

Let  $(u^*, x^*)$  be the solution of the optimal power flow described in Equations (2.1)-(2.3). **Under the assumption that zonal net positions are identical in the zonal dispatch as in the final  $(u^*, x^*)$  dispatch**, it becomes possible to rearrange the system-wide problem into independent zonal subproblems:

$$\min f_z(u_z, x_z) \quad (2.12)$$

Such that:

$$p_z(u_z, x_z) = 0 \quad (2.13)$$

$$q_z(u_z, x_z) \leq 0 \quad (2.14)$$

where  $f_z$  is the projection of cost function  $f$  on zone  $z$ , vector function  $p_z$  represents equality constraints applicable to zonal dispatch, notably supply adequacy to residual zonal demand, and  $q_z$  represents the corresponding inequality constraints, where no grid-related constraints remain. Let  $(\hat{u}, \hat{x})$  be the zonal optimum such that:

$$\hat{u} = \begin{pmatrix} \hat{u}_1 \\ \dots \\ \hat{u}_{N_z} \end{pmatrix}; \hat{x} = \begin{pmatrix} \hat{x}_1 \\ \dots \\ \hat{x}_{N_z} \end{pmatrix} \quad (2.15)$$

If we adapt this to the problem presented in Equations (2.4)-(2.10), it becomes clear that the solution vector  $\hat{P}$  for dispatchable generator outputs can be deduced from a simple merit-order application, i.e. by fulfilling residual zonal demand based on generators marginal costs. Comparison between vectors  $\hat{P}$  and  $P^*$  (extracted from  $u^*$ ) therefore allows the joint evaluation of zonal and final dispatches – and thus the measure of redispatching needs.

The fundamental hypothesis regarding the conservation of net

positions is further validated in (Marinho *et al.*, 2017b), with a sensitivity analysis involving 300 representative dispatch scenarios at a Pan-European level. For a number of zones that is close to twenty, they observe a maximal variation of 3% in redispatch efforts resulting from a 30% increase of net positions.

**The computational simplicity of this approach makes it relevant for the preliminary analysis of a large array of zonal configurations under diversified batches of dispatch scenarios.** In particular, it allows the assessment of multi-horizon impacts of bidding zone revision through the use of dispatch configurations that are representative of medium- to long-term power system evolutions. For example, this is employed by Burstedde who examines 2015 and 2020 dispatch scenarios in their 2012 study (Burstedde, 2012).

The findings from this section will provide the main framework for Chapters 3 and 4. Chapter 5 will nonetheless introduce an extended network reduction initiatives resulting in simulations that combine unit commitment and medium- to long-term capacity expansion planning.

## 2.2 ELABORATION OF A 30-BUS BENCHMARK GRID MODEL

The literature addressing congestion management, bidding zone revision or even network reduction often finds itself combining operational and economic analyses. As we also consider the computational challenges in some modelling approaches, it is not surprising to note a very common use of benchmark models with at most a few dozen nodes.

In a number of approaches, these models are used to conduct a first proof of concept before extrapolating the developed methods to large-scale grid models. This is the case of Cheng et al. (Cheng *et al.*, 2005) who perform network reduction on a six-bus test system before presenting results on a full grid model of the state of Illinois. Delgadillo et al. (Delgadillo and Reneses, 2013) use a three-area test system as a preliminary to their case study on counter-trading involving IEEE's Reliability Test System (RTS-96). Furthermore, in their approach to the definition of welfare-optimal bidding zones, Grimm et al. (Grimm *et al.*, 2017) successively employ eight test models with three to twenty-three buses.

In this section, we first conduct a review of available models and data that can be used as a proof of concept for bidding zone delineation and assessment. We then design our own 30-bus benchmark system which will be further used in Chapters 3 and 4.

### 2.2.1 A Review of Reference Test Models

Table 1.1 introduces a review of test models that are used in a selection of contributions addressing congestion management, network reduction, bidding zone delineation or system planning. We specifically highlighted the corresponding number of nodes and the references to conventional IEEE test systems.

Table 2.1: A Review of Reference Test Models

Ref.	Year	Main focus	IEEE 24-bus system	IEEE 30-bus system	IEEE 39-bus system	IEEE 118-bus system	Other		
							≤9 buses	10-19 buses	20-28 buses
(Cheng <i>et al.</i> , 2005)	2005	NR					✓		
(Oh, 2010)	2010	NR					✓		
(Huang, Bompard and Yan, 2011)	2011	CM		✓					
(Androcec and Krajcar, 2012)	2012	BZD						✓	
(Singh and Parida, 2013)	2013	CM			✓				
(Sarfati and Hesamzadeh, 2013)	2013	CM	✓						
(Oggioni and Smeers, 2013)	2013	CM					✓		
(Delgadillo and Reneses, 2013)	2013	CM	✓						
(Fezeu <i>et al.</i> , 2014)	2014	NR						✓	
(Shi and Tylavsky, 2014)	2014	NR					✓		
(Singh, Mahanty and Singh, 2015)	2015	CM		✓					
(Reza Salehizadeh, Rahimi-Kian and Oloomi-Buygi, 2015)	2015	CM	✓						
(Barrios <i>et al.</i> , 2015)	2015	SP				✓			
(Pena, Brancucci and Hodge, 2017)	2017	SP				✓			
(Grimm <i>et al.</i> , 2017)	2019	BZD					✓	✓	✓
(Pantoš, 2020)	2020	CM			✓				
(Prajapati and Mahajan, 2021)	2021	CM	✓						
<b>Count</b>			<b>4</b>	<b>2</b>	<b>2</b>	<b>2</b>	<b>5</b>	<b>3</b>	<b>2</b>
<b>NR:</b> Network Reduction / <b>CM:</b> Congestion Management / <b>BZD:</b> Bidding Zone Delineation / <b>UC:</b> System Planning.									

We draw two main observations from this overview. First, it is quite common for authors to design original test systems with less than ten nodes in order to illustrate complex methodologies regarding network

reduction or bidding zone delineation. These models are generally **illustrative of easily solveable dispatch configurations in order to highlight the effect of a specific methodology**, as when Oggioni and Smeers study the use of countertrading for congestion management in (Oggioni and Smeers, 2013), or for the identification of power system equivalents by Shi and Tylavsky in (Shi and Tylavsky, 2014). However, this choice of very small benchmark systems is sometimes required by optimization problems that are particularly computationally demanding, e.g. the identification of welfare-optimal bidding zones in (Grimm *et al.*, 2017).

Second, our review from Table I shows that **IEEE test systems are also very represented in recent contributions**. This series of reference test models has been introduced in the 1960s and refers to classical North-American case studies, such as the Western System 9-bus model or the New England 39-bus model. An extensive presentation of conventional IEEE test systems and their main applications is available in (Peyghami *et al.*, 2019).

From a more general perspective, the coexistence of reference IEEE test models and original benchmark systems illustrates a common academic concern regarding power system modelling approaches. On the one hand, IEEE systems provide comprehensive and coherent datasets that are suitable for most conventional frameworks, including the power flow simulations we are targeting in this work. On the other hand, authors may aspire to **original models that are representative of European voltage levels or emerging techno-economic concerns**. In that sense, Meinecke et al. (Meinecke, Bornhorst and Braun, 2020) mention distributed energy resources or modern voltage transformers as key motivations for the design of original benchmark systems.

A first avenue in this regard consists in the many updates from conventional IEEE test systems that have been performed over the years. For example, Peña et al. (Pena, Brancucci and Hodge, 2017) have been proposing an extended IEEE 118-bus system with enhanced renewable penetration. While the original IEE-118 bus test system is derived from a real-life transmission grid in the Midwestern United States, the model updated by Peña et al. is illustrative of three specific

areas of the Californian power system in compliance with 2024 projections from the Western Electricity Coordination Council. The authors named this model NREL-118 as it was issued in relation with the US National Renewable Energy Laboratory.

On a more European standpoint, Barrios et al. (Barrios *et al.*, 2015) provide another adaptation of the IEEE-118 test system that represents three German regions with compliant electrotechnics standards. This model is specifically proposed as a benchmark case for network expansion planning.

Although perfectly suitable for power flow simulations with high renewable penetration, **these benchmark models are generally representative of limited perimeters that are smaller than current European bidding zones**. Moreover, benchmark modelling efforts towards bidding zone delineation efforts supposes an ability to quickly analyze the resulting zone configurations, which may be more manageable with less buses involved. In the following section, we present our efforts to design an original grid model that includes only 30 buses and that is **suitable for benchmark case studies on the delineation of European bidding zones**. The resulting model will then be used for preliminary case studies in Chapters 3 and 4.

### 2.2.2 Designing an Original Benchmark Grid Model

As previously mentioned, the benchmark of zone delineation methods requires a model with limited spatial complexity in order to be able to quickly analyze competing zone revision trends. From a more general perspective, the conduct of optimal power flow simulations tends to bring the focus on the nodal scale – as opposed to region-wide system expansion planning for example. In this regard, it is no surprise that among the IEEE test cases, the IEEE 30-bus model is most commonly chosen for power flow studies – 32% of the contributions reviewed in (Peyghami *et al.*, 2019). On the other hand, 38% of the referenced system planning approaches rely on the IEEE-118 system, which further validates the choice of this model in (Barrios *et al.*, 2015; Pena, Brancucci and Hodge, 2017).

In our case, we therefore deemed relevant to set an objective of thirty

buses for the design of our original benchmark grid model. Nonetheless, the resulting model should **be representative of a large-scale power system** and not only a limited geographical perimeter that would be significantly smaller than the average European bidding zone. We thus opted for a total installed capacity of 150 gigawatts, including 90 gigawatts of renewable capacity – which meets the 60% projection of ENTSO-E’s TYNDP 2020 “National Trends” scenario for 2025 (ENTSO-E, 2020d) – and a demand range of 40 to 80 gigawatts – which is aligned with current demand extrema in proportion to the installed capacity over the ENTSO-E perimeter (ENTSO-E, 2019b).

In order to avoid tackling network reduction issues over a full realistic European grid model, we based our model building approach on **realistic elementary bricks from the European power system**. We therefore used public data from the “E-Highway 2050” European project (e-HIGHWAY 2050, 2014), which provides a partition of the ENTSO-E perimeter into 117 clusters, notably based on demographics, existing generations capacities and climate characteristics for RES deployment.

We manually selected six clusters with the constraints of representing different geographical areas and reaching 60% of installed renewable capacity. This resulted in the selection of clusters from Spain, France, Italy, Germany, Poland and Sweden. The capacity of each cluster was then distributed over five nodes and normalized in order to reach the target 150 gigawatts. We designed an ad-hoc grid structure with 400kV lines presenting a 1,500 megawatts capacity, and made sure power flow simulations were tractable under this configuration. Even though a 1,500 line rating is way above conventional line capacities in Europe, this value was set to illustrate realistic exchange volumes between small areas of the European power system – which are generally connected by several lines. The resulting capacity distribution is presented on Figure 2.1. More details on the model specifications and the variations introduced in Section 4.2 are available in Appendix A.

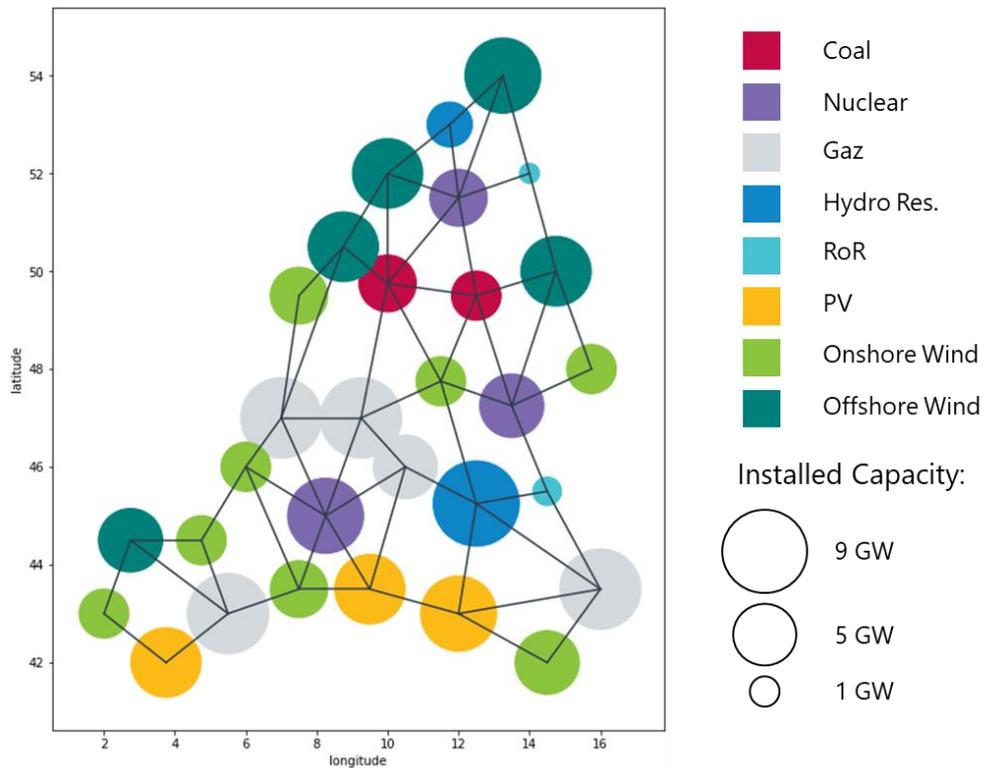


Figure 2.1: 30-Bus Benchmark System - Installed Capacities and Grid Structure.

The nodal distribution of demand was derived from the original E-Highway 2050 demand levels. We then associated elementary clusters in order to design **an ad-hoc standard configuration with four zones that have complementary profiles** in terms of demand level, installed generation capacity and integration of demand capacity – as presented in Figure 2.2. This choice of four zones creates an average zonal generation capacity of 37.5 GW, which is slightly higher than the 32GW European average (ENTSO-E, 2019b). The capacity of intra-zonal transmission lines was raised to 2,000 megawatts in order to favor internal exchanges and hereby highlight this original zone configuration into the model dynamics.

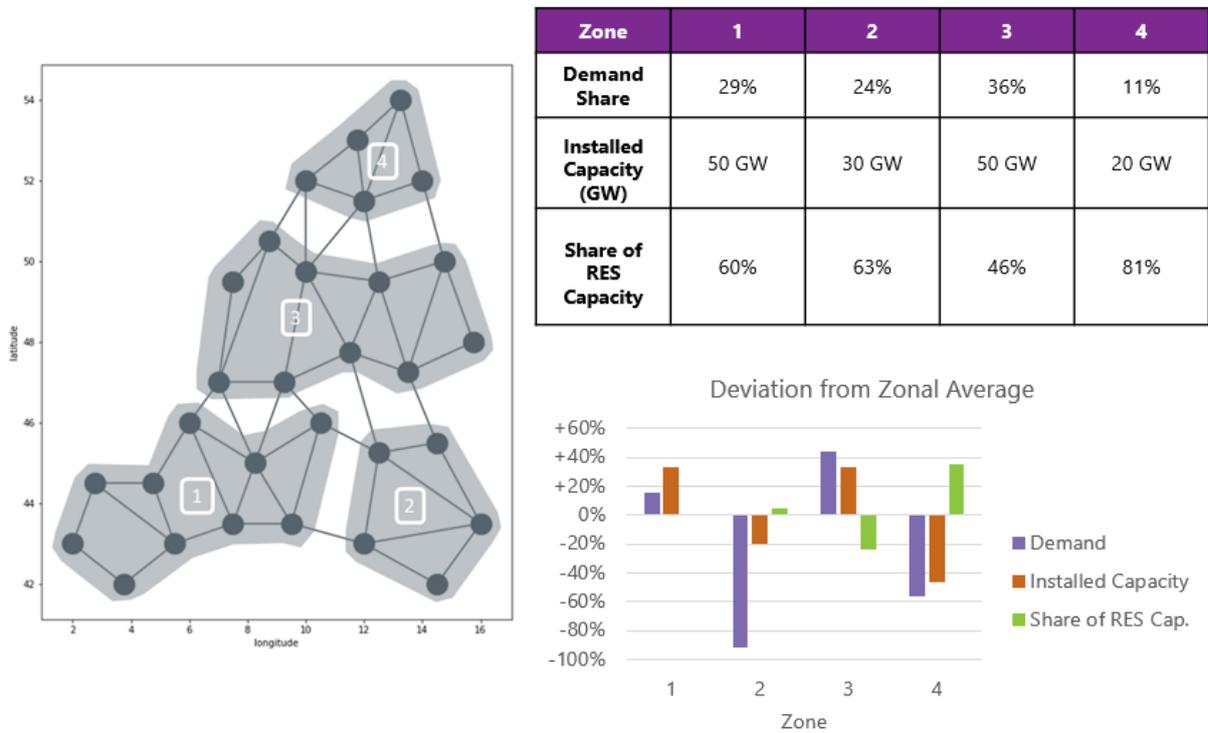


Figure 2.2: 30-Bus Benchmark Model - Original Zonal Delineation

Table 2.II presents a comparison of our original 30-bus benchmark system to the IEEE-30 bus test system and previously cited adaptations of the IEEE-118 bus system. Our test system stands out for generally high generation and transmission line capacities, which validates the objective of representing a large-scale power system with a limited number of nodes. This type of model is reminiscent of simulations approaches that are based on reduced models representing only the highest voltage levels, as performed by Marinho et al. in (Marinho *et al.*, 2017b) or by transmission system operators from the Nordics region in (ENTSO-E, 2022d).

Table 2.II: Comparison of test systems

Zone	Nodes	Zones	Share of RES Capacity	Installed Capacity (GW)	... av. per zone (GW)	...av. per node (MW)	Av. Line Capacity (MW)
<b>NREL-118</b> (Pena, Brancucci and Hodge, 2017)	118	3	64%	40.5 GW	13.5 GW	343 MW	873 MW
<b>Barrios</b> (Barrios <i>et al.</i> , 2015)	120	3	39%	51.7 GW	17.2 GW	431 MW	871 MW
<b>IEEE-30</b> (30 Bus Power Flow Test Case, 1993)	30	1	0%	0.435 MW	0.435 GW	14.5 MW	48 MW
<b>30-Bus Benchmark System</b>	30	4	60%	150 GW	37.5 GW	5,000 MW	1,890 MW

Moreover, our test system differs from other example by the fact that the **average line capacity is inferior to the average nodal generation capacity**. This suggests the occurrence of grid-constrained dispatch situations, which is particularly useful to benchmark automated methods to generate congestion-compliant zone configurations. In this purpose, Chapter 3 presents optimal power flow simulation results with the adapted NREL -118 model from (Pena, Brancucci and Hodge, 2017) for which line capacities have been reduced to an average of 600 megawatts due to the lack of observed congestion.

## 2.3 DATA AND MODELS FOR PAN-EUROPEAN STUDIES

In this section, we address the availability of models and data for optimal power flow simulations at a Pan-European scale. We therefore combine an overview of previous realistic case study involving bidding zone delineation and congestion management and public grid models from both the academia and the industry.

We then introduce the Pan-European grid model that is featured in the remainder of this work, introducing comparisons with reference models, as well as the selection of data involved in modelling scenarios.

### 2.3.1 A Review of Available Data and Models

As previously mentioned, the analysis and evaluation of market design policies have pushed for unprecedented modelling efforts, whether we consider data collection, simulation chains or even the computational aspect. In particular, the second Bidding Zone review has led to an ambitious coordination of transmission system operators around the Pan-European-wide computation of locational marginal prices (ENTSO-E, 2022d), in line with an ACER methodology that features advanced grid partitioning methods (ACER, 2021b).

**In a context where the elaboration of public policies requires large-scale technical efforts**, access to large-scale realistic data and models becomes a matter of concern to propose relevant academic contributions. This is consequently no surprise that the last few years have seen the **multiplication of open data initiatives** regarding the development of public grid models and simulation tools.

According to Medjroubi et al. (Medjroubi *et al.*, 2017), **four main types of static grid models can be identified depending on the representation of grid constraints**. The first two types consist in **single-node and multi-region models**, where grid constraints are either disregarded or integrated through flow limitations between regions.

The third type of model is referred as *DC model* and corresponds to the DC-OPF simulations that have been discussed in Section 2.1.1. A

As detailed in Equations (2.8)-(2.10), line flows are both constrained by line capacities and their intrinsic reactance. In particular, if line  $l$  is connected to bus  $b$ , Equation (2.9) simply becomes:

$$f_l = PTDF_{b,l} \times P_b^{Inj} \quad (2.16)$$

Where  $PTDF_{b,l}$  only depends on the reactance of line  $l$ . In particular, line reactances tend to be standardized according to conventional line ratings of a given power system. More details on conventional assumptions for line reactance values in Germany can be found in (Egerer *et al.*, 2014).

Moreover, line reactances – and other characteristics like resistance – vary linearly with line lengths, and are often expressed in Ohm per kilometer. **DC static grid models are therefore highly dependent on geographical bus coordinates that allow the computation of line characteristics.** This additional data requirement therefore represents the main divergence of *DC models* from rudimentary copper-plate multi-region models.

Finally, the fourth model type identified by Medjroubi *et al.* (Medjroubi *et al.*, 2017) is the **full AC model**, which requires additional parameters and constraints in order to address **both active and reactive power** behaviours. While conventional optimization solvers tend to allow the computation of large-scale AC power flows, this formalism requires a **significant amount of additional data to secure model tractability.** This notably includes coherent system-wide voltage profiles and the additional modelling of voltage control.

For a long time, the availability of spatially referenced Pan-European grid data has therefore justified **ambitious model construction efforts based on very limited sources.** Two decades ago, Zhou and Bialek (Zhou and Bialek, 2005) notably introduced a model of the first synchronous UCTE region, which represents most of today's Continental Europe synchronous area, based on minute manual extraction of 1,254 bus coordinates from the UCTE transmission map. An updated version of this model including the Balkan region was released in 2013 by Hutcheon and Bialek (Hutcheon and Bialek, 2013).

While these models have been referenced and used as such in the literature, they are illustrative of a tradition of consolidating European grid models through the **aggregation of public sources**. As reviewed by Egerer et al. in (Egerer *et al.*, 2014), public data from ENTSO-E and specific European TSOs is already useful for collecting transmission network characteristics, generation capacities and demand time series. In particular, authors addressing bidding zone revision specifically refer to **various editions of ENTSO-E's Ten Year Network Development Plan (TYNDP)** (ENTSO-E, 2021d) in the construction of their model. This is the case with Breuer and Moser in (Breuer and Moser, 2014), Felling and Weber in (Felling and Weber, 2018) and Marinho et al. in (Marinho *et al.*, 2017b).

While additional assumptions regarding fuel prices can generally be found in other publications from European institutions (Egerer *et al.*, 2014), authors may resort to commercial services to obtain detailed generator specifications (Egerer *et al.*, 2014; Marinho *et al.*, 2017b). Extensive public databases regarding climate data and renewable generation are nonetheless available, notable the Renewables.ninja (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016; *Renewables.ninja*, 2022) and The Wind Power (The Wind Power, 2022) platforms.

The availability of **geographical coordinates nonetheless remain very limited**, showing few progression since Zhou and Bialek's manual georeferencing. Egerer et al. (Egerer *et al.*, 2014) refer to aerial imaging as the main source for geographical informations, while the static grid model in (Marinho *et al.*, 2017b) is based on spatial coordinates from a 2008 UCTE publication (UCTE, 2008).

The significant efforts regarding static grid model construction with public sources translates in the literature through two types of initiatives. On the one hand, Pan-European grid models are often **developed unilaterally by a university or a research group**, which is a standard in the literature regarding European bidding zones. This is the case with the CWE models introduced by Burstedde in (Burstedde, 2012) and Felling and Weber in (Felling and Weber, 2018), the Continental Europe model used by Breuer and Moser in (Breuer and Moser, 2014) or the Pan-European model presented by Marinho

et al. in (Marinho *et al.*, 2017b).

On the other hand, the past few years have seen **the emergence of open source grid models** supported by academic actors and large networks of online users. For example, the ELMOD model presented by Egerer et al. in (Egerer *et al.*, 2014) integrates fourteen countries, with applications regarding renewable capacity expansion at a European scale. This public grid model was developed by the Technical University of Dresden, and a detailed open-source model of the German perimeter was released in 2016 (Egerer, 2016).

Since the release of the ELMOD project in 2016, several open-data European grid models have emerged based on the OpenStreetMap power grid framework (power grid, OpenStreetMap power grid and power grid, 2022). A comparison of three initiatives is performed in (Heitkoetter *et al.*, 2019) over the German perimeter: the GridKit and SciGRID models, subsidied by German public funds between 2014 and 2017, and the osmTGmod tool, developed by the University of Flensburg and the Wuppertal Institute for Climate, Environment and Energy from 2015 to 2017. Although these models rely on a worldwide open-data infrastructure, they were mostly consolidated over the German perimeter, and no European-wide application was noted since their release.

The most advanced Pan-European open-source grid model initiative to this day must therefore **be the “Python for Power System Analysis” initiative (PyPSA)**, with the 2017 release of the PyPSA-eur model (Hörsch *et al.*, 2018). This project relies on the parallel development of a Python library for power system analysis by the Frankfurt Institute for Advanced Studies and the construction of a Pan-European grid model in collaboration with the Karlsruhe Institute of Technology. Grid data were notably extracted from ENTSO-E’s Interactive Grid Map (ENTSO-E, 2022c). A DC-OPF simulation based on a 2013 dispatch configuration is presented in (Hörsch *et al.*, 2018).

This model notably relies on simplifying assumptions regarding line capacities, using standardized values according to voltage levels and the number of conductors. While this type of assumptions is very common, published DC-OPF results show significant load shedding –

up to 1 gigawatt - at the vicinity of areas where electricity demand is most concentrated. This could suggest that the model disregards specific grid reinforcements that nonetheless appear in TYNDP data (ENTSO-E, 2020e). A PyPSA-eur-sec version is nonetheless under development since 2020, with the integration of sector coupling and explicit intention to improve model reliability (PyPSA-Eur-Sec, 2022).

Table 2.III: A Review of European Static Grid Models.

Model ID.	Ref.	Year of Publication	Studied Period	Perimeter	N. of Nodes	N. of Lines
NEULING	(Burstedde, 2012)	2012	2015/2020	Central Western Europe	79	434/446
Hutcheon and Bialek	(Hutcheon and Bialek, 2013)	2013	N:A	Continental Europe	1494	2322
Breuer and Moser	(Breuer and Moser, 2014)	2014	2016-2018	Continental Europe	Not Indicated	Not Indicated
Marinho et al.	(Marinho <i>et al.</i> , 2017b)	2017	2013	Pan-European	2842	3739
Felling and Weber	(Felling and Weber, 2018)	2018	2020	Central Western Europe	2200	3200
ELMOD	(Egerer <i>et al.</i> , 2014)	2014	2011	Pan-European	2120	3150
ELMOD-DE	(Egerer, 2016)	2016	2012	Germany	438	697
GridKit	(Heitkoetter <i>et al.</i> , 2019)	2017	N/A	Germany	1849	2166
SciGrid	(Heitkoetter <i>et al.</i> , 2019)	2017	N/A	Germany	468	774
osmTGmod	(Heitkoetter <i>et al.</i> , 2019)	2017	N/A	Germany	811	1054
PyPSA-eur	(Hörsch <i>et al.</i> , 2018)	2017	2013	Pan-European	3657	6001
TYNDP 2020	(ENTSO-E, 2020e)	2020	2025-2040	Pan-European	9875	15720

Table 2.III presents a summary of the reviewed grid models. Even though the proposed models never meet the level of details of the recurrent TYNDP publications, academic initiatives and large-scale open data projects have allowed the **development of large-scale grid models of the European power system that are suitable for DC-OPF simulation**. In the next section, we thus discuss the qualities and limitations of the static grid model chosen for this study.

### 2.3.2 Presentation of our Pan-European Grid Model

The “Case Study” static grid model used in this work can be interpreted as an update from the Pan-European grid model introduced by Marinho et al. in (Marinho *et al.*, 2017b). The original transmission grid structure is derived from the same original UCTE 2008 grid model (UCTE, 2008), yet it has been updated to meet ENTSO-E’s TYNDP 2020 projections for 2025, 2030 and 2040 under the “National Trends” scenario.

The “National Trends” TYNDP scenario is presented as **in line with the European Union’s 2050 decarbonation objectives** (ENTSO-E, 2020d). It corresponds to the aggregation of 2021-2030 National Energy Climate Plans provided by Member States in 2019 as required by the 2018 Regulation on the Governance of the Energy Union and Climate Action (European Commission, 2018). In particular, this scenario is in line with the objective of a 32% penetration of renewable sources in the final energy consumption by 2030. It targets a 62% share of renewable sources in the 2030 electricity consumption, raised to 73% in 2040. Annual electricity demand is expected to increase by 11% between 2025 and 2040.

This results in an extended grid model which key dimensions are presented in Table I.IV. Considering the obstacles surrounding spatial data collection, the level of details in grid representation is heterogeneous. On the one hand, **the grid structure of twelve main bidding zones is extensively represented** and concentrate the vast majority of modeled grid elements: Austria (AT), Belgium (BE), Czech Republic (CZ), West Denmark (DK1), France (FR), Germany (DE), Italy (IT), Netherlands (NL), Poland (PL), Slovakia (SK), Slovenia (SL), and Switzerland (CH). On the other, **eleven additional areas that are less interconnected with the continental grid are represented with only a few nodes**, namely Croatia (HR), East Denmark (DK2), Great Britain (GB), Greece (GR), Hungary (HU), the Iberian Peninsula (ES + PT), Lithuania (LT), Norway (NO), Serbia (RS), Sweden (SE) and Ukraine (UA). A similar modelling approach was introduced by Nordic transmission system operators towards continental bidding zones in (ENTSO-E, 2022d). The overall 2025 grid structure is presented in Figure 2.3.

Table 2.IV: Key Model Dimensions for 2025, 2030 and 2040.

Year	N. of Buses	N. of Lines	N. Of Generators
<b>2025</b>	3,051	4,064	4,550
<b>2030</b>	3,066	4,099	4,426
<b>2040</b>	3,104	4,151	4,233

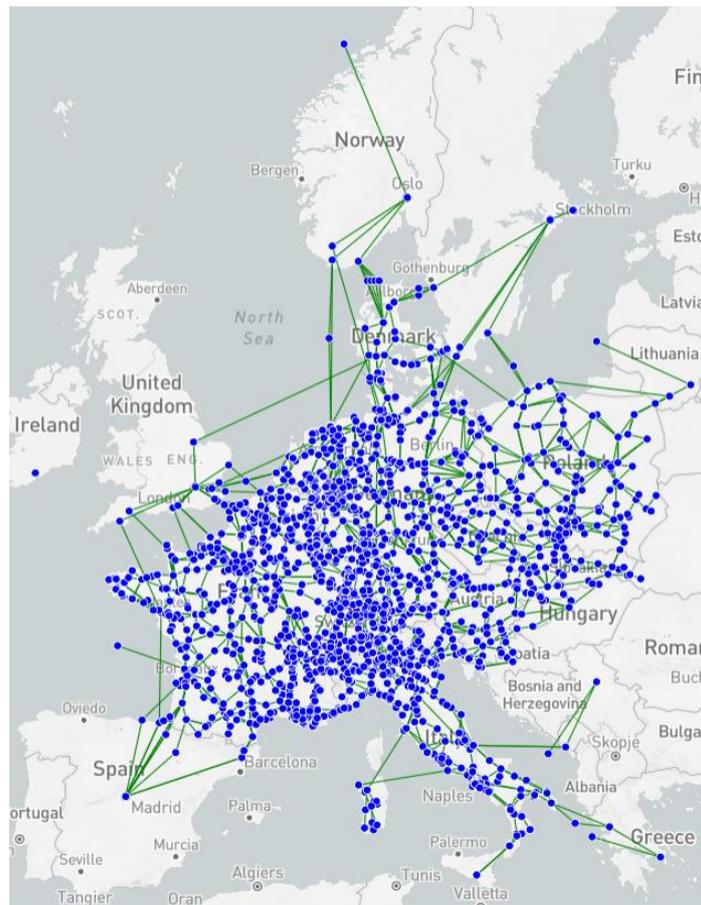


Figure 2.3: 2025 Grid Structure (Map from [openstreetmap.org](https://www.openstreetmap.org))

Thermal generators feature traditional and CHP units powered by gas, hard coal, lignite or oil, gas and oil-powered combustion turbines, and nuclear units. Other generating technologies include reservoir and run-of-river hydro, onshore and offshore wind and PV.

Nodal load distribution, line and generator capacities and zonal generation cost assumptions are also derived from the “National Trends” scenario of TYNDP 2020. The 2025-2040 evolution of installed capacities, which is aligned with the “National Trends” scenario, is represented on Figure 2.4.

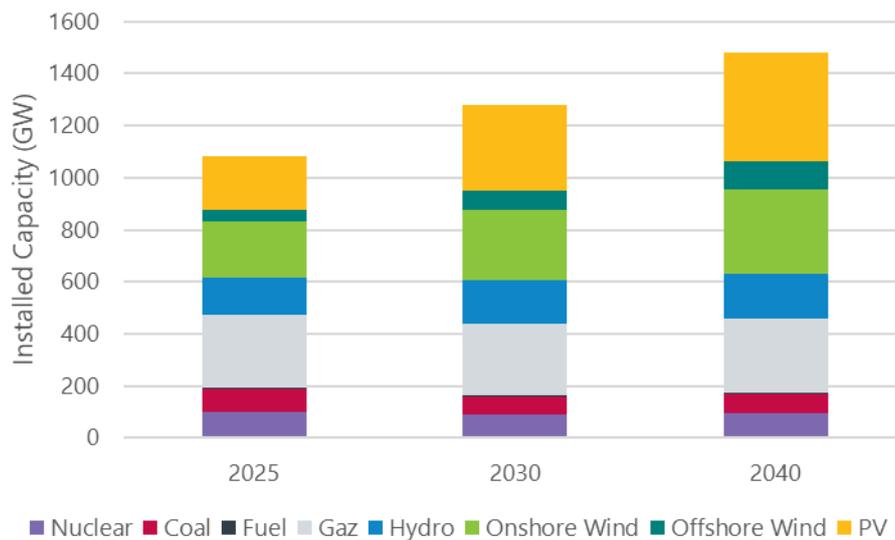


Figure 2.4: Evolution of Installed Generation Capacities – Case Study.

Figure 2.5 presents a comparison of grid structures between ENTSO-E’s real-life transmission infrastructure, the PyPSA-Eur model and our case study model, including 220, 300 and 380kV lines. Due to the **simplification of non-continental bidding zones**, the total circuit length of our model appears significantly lower than the two other examples (sources include (Hörsch *et al.*, 2018; ENTSO-E, 2020e)).

Nonetheless, Figure 6 tends to show that our model is at least **as detailed as PyPSA-Eur over the bidding zones that are extensively represented**. Moreover, the identification of TYNDP 2020 network elements to previously aggregated geographic data allows our model to be more precise than PyPSA-Eur in terms of the representation of line capacities.

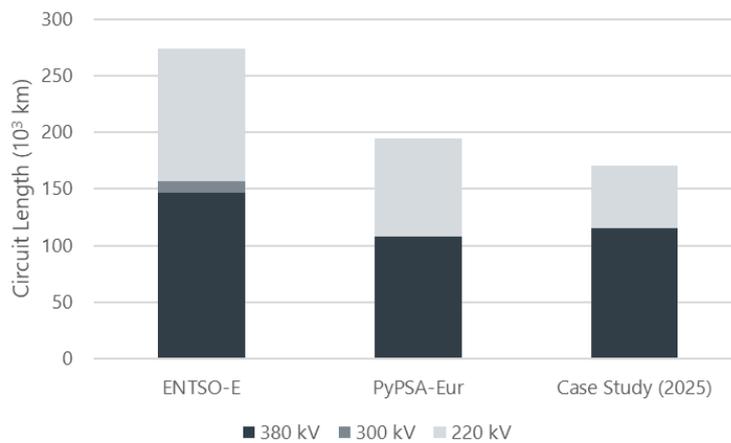


Figure 2.5: Comparison of Circuit Lengths per Voltage Level.

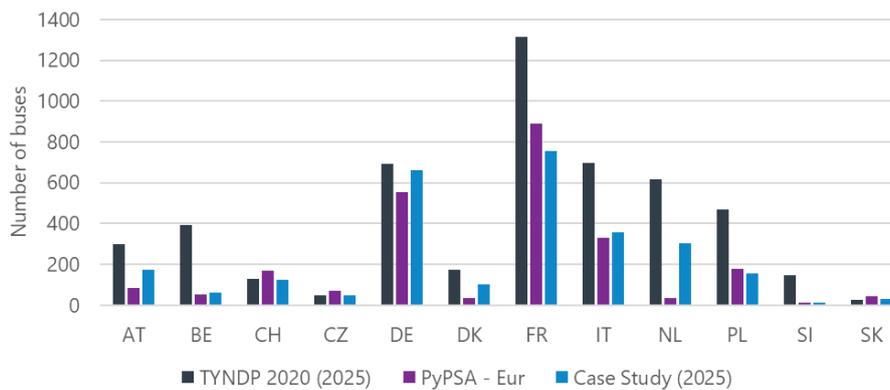


Figure 2.6: Number of Substations / Buses Over Selected Bidding Zones.

Finally, since PyPSA-Eur was first aligned with early 2010s dispatch configurations, it is no surprise to note a divergence from the projected 2025 generation fleet – see Figure 2.7. In spite of less detailed grid

representation of non-continental bidding zones, our case study was more specifically **designed to meet the “National Trends” multi-horizon system trajectory.**

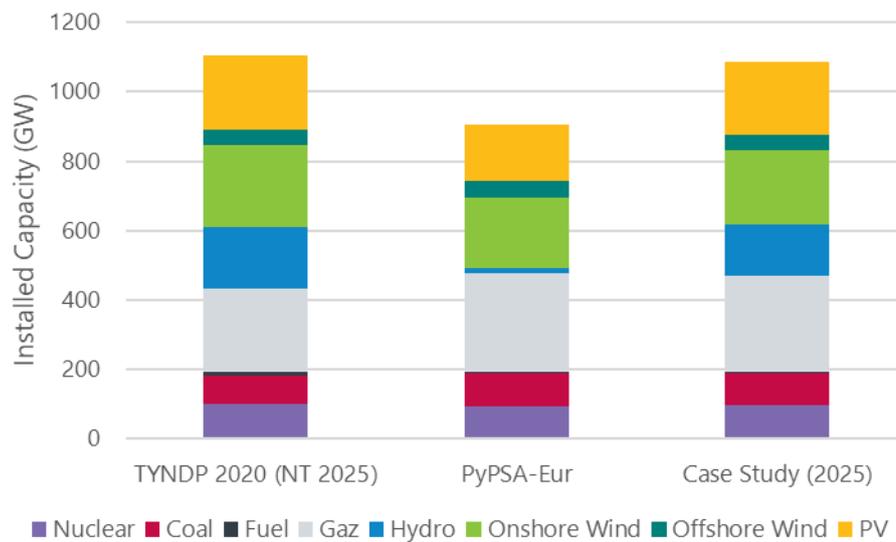


Figure 2.7: Comparison of Installed Capacities per Generation Technology.

While it is not strictly Pan-European, our model provides an extensive representation of Continental Europe with relevant interconnections to peninsular areas. It is therefore a good candidate **for addressing the Pan-European impacts of an evolution of bidding zones, provided the considered revision are mostly located on the continental area.** This will of course affect the candidate bidding zone reconfigurations that we will consider in the next chapters.

## KEY FINDINGS – CHAPTER 2

In this chapter, we have set the methodological basis for the identification and assessment of possible evolutions of European bidding zones. We first presented the formalism of optimal power flow simulations with direct current approximation, then discussed how it can be adapted to the techno-economic evaluation of a given bidding zone delineation.

We then investigated the availability of benchmark grid models in order to test zone delineation methods and evaluation indicators before extrapolation to realistic large scale European grid models. This resulted in the **development of a custom 30-bus benchmark grid model**, which will be featured for preliminary case studies in Chapters 3 and 4.

After another dive into the publicly available data and grid models, this time from a realistic, European perspective, **we introduced the Pan-European static model that constitutes the main support for the simulations conducted in this work.**

This last section highlighted the emergence of **large scale research initiatives dedicated to the elaboration of open-source Pan-European grid models** – which notably includes PyPSA-Eur.

Nonetheless, neither open source initiatives nor in-house model reconstitution by research teams seem to currently match the exhaustiveness of TYNDP dataset publications – which nonetheless do not include key features like spatial coordinates. In this work, the chosen model therefore results from **a compromise with the choice to prioritize a more restricted geographic area while securing a relevant short- to long-term system trajectory.**

As large-scale power system simulations are central to a number of current European energy policy topics, the relevance of open-source models in academic and institutional works should gain importance in the years to come.



### **3 DESIGNING ALTERNATIVE ZONE CONFIGURATIONS.**

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In this chapter, we focus on automated network partitioning methods and how they can be used to design candidate delineations for alternative bidding zones.

**Network partitioning – also referred to as bus selection, bus clustering or bus aggregation** – has been present in the literature for several decades, with **no systematic link to zonal pricing**. In fact, early occurrences show a computational interest for network reduction, either for congestion-compliant market studies (Cheng *et al.*, 2005; Shi and Tylavsky, 2014), grid stability analysis (Wang *et al.*, 1997) or system planning (Oh, 2010). As such, they often feature areas with nodal or no cohesive market design, like the State of Illinois in (Cheng *et al.*, 2005) or entire North American Interconnections in (Wang *et al.*, 1997; Oh, 2010; Shi and Tylavsky, 2014).

On the other hand, **not every intent to address alternative delineations for European bidding zones has involved automated bus selection**. In addition to the expert-based configurations presented in the First Edition of the Bidding Zone Review (ENTSO-E, 2018b), the specific possibility of a split of the German bidding zone has motivated several contributions with empirically defined delineations (Egerer, Weibezahn and Hermann, 2016; Plancke, De Jonghe and Belmans, 2016; Zamora and Christoph Weyhing, 2021).

Nonetheless, experience-based zone delineation generally requires access to extensive reporting of congestion phenomena over a given grid portion, which justifies using it on restrained perimeters. In this regard, automated bus selection therefore represents an opportunity for designing **zone delineations that efficiently integrate grid constraints on a pan-European basis**.

Section 3.1 reviews conventional techno-economic criteria and bus aggregation methods and their relevance regarding revision efforts for European bidding zones. In Section 3.2, we apply relevant bus clustering approaches to the previously introduced NREL-118 and 30-bus benchmark systems, discussing necessary adaptations before extrapolation to our pan-European static grid model. In Section 3.3, we present enhanced versions of previous clustering algorithms that we use to create nine candidate configurations for alternative European

bidding zones.

### 3.1 A REVIEW OF AUTOMATED APPROACHES TO BIDDING ZONE DELINEATION.

Input criteria and bus partitioning algorithms have been regularly discussed in the literature (Van Den Bergh *et al.*, 2016; Marinho *et al.*, 2017b; Chicco *et al.*, 2019), generally promoting grid partitions that are deemed more efficient from a congestion management point of view. In the literature, most attempts towards automated zone delineation are indeed motivated by a willingness to **align zone borders to structural congestion occurrences on the grid.**

However, a notable exception to this trend resides in the e-Highway-2050 European project (e-HIGHWAY 2050, 2014), featuring a partition of the pan-European power system into approximately one hundred geographical clusters. The partition algorithm was designed to ensure cluster coherence regarding demographics, existing hydro and thermal capacities and potential for renewable sources development. Grid constraints were consequently not featured in the partitioning process, implying that bottlenecks located on internal lines may affect cross-cluster exchanges in the reduced model.

In line with European legislations that promote the consideration of structural congestion ((European Commission, 2015, 2019)), this work will therefore focus on **automated bus selection methods that allow integrating grid constraints within the zone delineation process.**

#### 3.1.1 A Review of Bus Selection Criteria.

Chicco *et al.* (Chicco *et al.*, 2019) identify **two main bus selection criteria throughout the literature on bidding zone delineation.** Bus selection based on **locational marginal prices (LMPs)** is found in fifteen out of the thirty-one reviewed contributions, followed by the use of **Power Transfer Distribution Factors (PTDFs)** with five occurrences.

More rarely found criteria include derivatives from PTDFs and LMPs but also Available Transfer Capacities (ATC), featured in (Shayesteh *et al.*, 2015), or indicators relative to power injections, as approached through Monte-Carlo simulations in (Yang and Zhou, 2006). As a

complement, specific contributions present an implicit approach to grid constraints, introducing electrical distances that emulate equivalent impedances between nodes as a clustering input. This approach is featured in (Fezeu *et al.*, 2014) and has also been used in the scope of the e-Highway 2050 project (Lumbreras *et al.*, 2015).

Both PTDF and LMP-based clustering have been **present in the literature since the early years of European electricity market deregulation**. Back in 2008, Olmos and Pérez-Arriaga (Olmos and Pérez-Arriaga, 2008) presented a PTDF-based bus selection approach to define single-price areas in the Iberian Peninsula and Southwestern Europe, combining K-Means clustering and an autoregressive Kohonen algorithm. The same year, Imran and Bialek (Imran and Bialek, 2008) introduced a Fuzzy C-Means clustering algorithm applied to LMPs on a model of Continental Europe.

PTDF-based clustering has later been used for diversified purposes. Since PTDFs represent the influence of node injections on the flow of critical lines in the system, this approach is popular for specific zone delineation objectives like loop-flow reduction (Kłós, Wawrzyniak and Jakubek, 2015) or calculating generation shift-keys (Van Den Bergh and Delarue, 2016). In line with previously discussed North-American applications (Cheng *et al.*, 2005; Oh, 2010; Shi and Tylavsky, 2014), PTDF-based clustering is also involved in more conventional network reduction efforts, as performed on Continental Europe model in (Marinho *et al.*, 2017a). From an economic perspective, Van den Bergh *et al.* (Van Den Bergh *et al.*, 2016) use PTDF-based grid partitioning to address market impacts of zone reconfiguration on another benchmark model of Continental Europe (Zhou and Bialek, 2005), especially addressing the penetration of thermal units.

**This economic angle is usually more associated with LMP-based zone delineation efforts**. For example, Burstedde (Burstedde, 2012) uses Hierarchical clustering to investigate the sensitivity of both price formation and redispatching costs to a reconfiguration of bidding zones in the Central Western Europe (CWE) region. Breuer and Moser (Breuer, Seeger and Moser, 2013; Breuer and Moser, 2014) propose a similar approach based on a genetic algorithm applied to a model of Continental Europe, addressing market power and generation outputs.

This economic perspective is also explored by Felling and Weber (Felling and Weber, 2016) who combine LMPs and a node weight system that highlights the relevance of each node to supply adequacy. In parallel of the PTDF approach featured in (Marinho *et al.*, 2017a), Marinho et al. (Marinho *et al.*, 2017b) use LMP-based clustering in their attempt to define European bidding zones that efficiently scale-down redispatching needs.

This dichotomy between PTDF and LMP-based clustering can be interpreted as a fundamental divergence of both zone delineation rationales. As pointed out by Van den Bergh et al. (Van Den Bergh *et al.*, 2016), **LMP-based bus selection inherently creates clusters that minimize intra-zonal congestion**, for congestion phenomena tend to accentuate LMP differentials. On the other hand, buses with similar PTDF matrixes – thus comparable influence on critical lines – will generally be involved in the same congestion phenomena. **PTDF-based zone delineation will therefore favor the concentration of congested lines within clusters.**

**Selecting buses based on locational marginal prices therefore appears more compliant to institutional European guidelines** as interpreted by ENTSO-E in (ENTSO-E, 2021a), stating that bidding zones should not enclose structural grid constraints – ie congestion that are frequent and restrictive for cross-zonal exchanges. This explicitly motivates the choice of LMPs as a clustering criterion by Felling and Weber in (Felling and Weber, 2018), and justifies their use in the remainder of this work.

Nonetheless, **neither LMPs nor PTDFs are sufficient to ensure grid connexity and overall spatial coherence of the resulting clusters on a large-scale model.** Chicco et al. (Chicco *et al.*, 2019) regret the absence of consideration for physical node connections in many bus selection approaches, leading to systematic post-processing efforts. This is addressed by the use of **node adjacency matrices** in (Felling and Weber, 2018; Colella *et al.*, 2021; Schönheit *et al.*, 2021), which constrains or at least requires adaptations regarding associated clustering algorithms. With a more straightforward approach, Marinho et al. (Marinho *et al.*, 2017b) suggest **weighting locational marginal prices with geographical coordinates** when calculating distances

between nodes. Both geographical distance and node adjacency are considered in the efforts of Chavent et al. (Chavent *et al.*, 2018) to enhance hierarchical clustering with spatial constraints. The formal integration of spatial constraints into clustering frameworks will be discussed in Section 3.3.

### 3.1.2 A Review of Clustering Algorithms.

Table 3.1 presents the bus selection methods featured in the previously cited contributions. In accordance with the review performed in (Chicco *et al.*, 2019), most approaches correspond to **conventional clustering algorithms**, which general description and classifications can be found in (Saxena *et al.*, 2017).

Apart from the **few examples of empirical, expert-based approaches** (Egerer, Weibezahn and Hermann, 2016; Plancke, De Jonghe and Belmans, 2016; ENTSO-E, 2018b; Zamora and Christoph Weyhing, 2021), three contributions stand out from traditional clustering techniques while still relying on automated bus selection. On the one hand, references (Wang *et al.*, 1997) and (Oh, 2010) correspond to more technical network reduction efforts that respectively involve generator aggregation according to coherent rotor oscillations and iterative reduction of the bus admittance matrix.

On the other hand, Grimm et al. (Grimm *et al.*, 2017) introduce a mixed-integer nonlinear trilevel optimization model for determining welfare-optimal bidding zones on a given model. In spite of encouraging results on up to 28-bus systems, this type of advanced optimization approach does not appear suitable for the tractability requirement of a large-scale European model.

Table 3.1: A Review of Bus Selection Methods.

Ref.	Fuzzy c-Means	Genetic	K-Means	K- Medoids	Kohonen	Hierarchical	Spectral	Other	Empirical
(Cheng <i>et al.</i> , 2005)	✓								
(Shi and Tylavsky, 2014)			✓						
(Wang <i>et al.</i> , 1997)								✓	
(Oh, 2010)								✓	
(ENTSO-E, 2018b)						✓			✓
(Plancke, De Jonghe and Belmans, 2016)									✓
(Egerer, Weibezahn and Hermann, 2016)									✓
(Zamora and Christoph Weyhing, 2021)									✓
(Van Den Bergh <i>et al.</i> , 2016)						✓			
(Marinho <i>et al.</i> , 2017b)			✓	✓		✓			
(e-HIGHWAY 2050, 2014)			✓						
(Shayesteh <i>et al.</i> , 2015)			✓				✓		
(Yang and Zhou, 2006)	✓								
(Fezeu <i>et al.</i> , 2014)			✓						
(Lumbreras <i>et al.</i> , 2015)				✓					
(Olmos and Pérez-Arriaga, 2008)			✓		✓				
(Imran and Bialek, 2008)	✓								
(Kłós, Wawrzyniak and Jakubek, 2015)						✓			
(Van Den Bergh and Delarue, 2016)						✓			
(Marinho <i>et al.</i> , 2017a)						✓			
(Burstedde, 2012)						✓			
(Breuer, Seeger and Moser, 2013)		✓							
(Breuer and Moser, 2014)		✓							
(Felling and Weber, 2016)						✓			
(Felling and Weber, 2018)						✓			
(Colella <i>et al.</i> , 2021)			✓			✓	✓		
(Schönheit <i>et al.</i> , 2021)						✓			
(Grimm <i>et al.</i> , 2017)								✓	
<b>Count</b>	<b>3</b>	<b>2</b>	<b>6</b>	<b>2</b>	<b>1</b>	<b>11</b>	<b>2</b>	<b>3</b>	<b>4</b>

Back to a conventional clustering perspective, **all presented methods share at least two main inputs**. First, they require **an input number of zones set by the user**. Second, they need to be specified **a metric that is used to affect each bus to a specific cluster**. The vast majority of the reviewed contributions rely on **the Euclidean distance**, which we will also use in the following sections. Nonetheless, exceptions are to be noted, such as the electrical distance used in (Fezeu *et al.*, 2014; Espejo, Lumbreras and Ramos, 2018), the enforcement of Ward's minimum variance criterion in (Burstedde, 2012; Van Den Bergh *et al.*, 2016) and the Manhattan distance associated with genetic algorithms in (Breuer, Seeger and Moser, 2013; Breuer and Moser, 2014).

As observed in (Chicco *et al.*, 2019), **K-Means and Hierarchical approaches are very popular in the literature**, especially considering the Fuzzy-c-Means and K-Medoids methods can be seen as K-Means derivatives. They are also illustrative of two complementary approaches to network partition. On the one hand, the K-Means algorithm is often described as a **top-down approach** (Marinho *et al.*, 2017b) since it relies on the initialization of a fixed number of clusters that are then fitted to the data. On the other hand, Hierarchical clustering starts with a maximal number of clusters and carries out mergers until reaching the desired number of zones. This approach is therefore deemed “**aggregative**”, or “**bottom-up**” (see Fig. 3.1). This antagonism between the top-down and bottom-up rationales is likely to impact the adaptation of the algorithms to the European bidding zone delineation problem. In the remainder of this chapter, we will therefore address both K-Means and Hierarchical approaches.

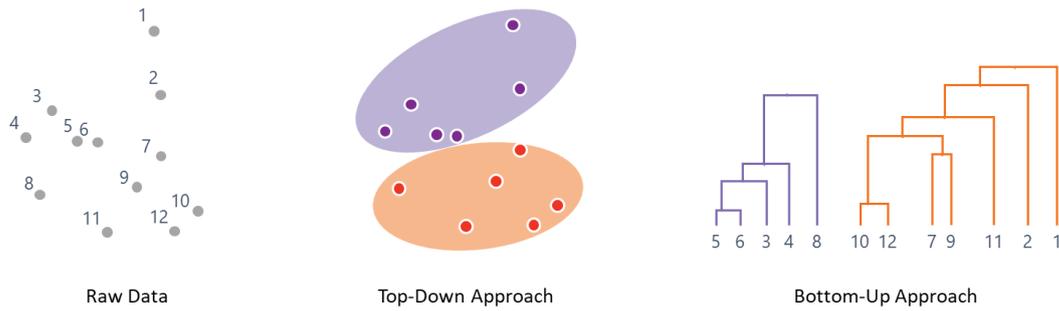


Figure 3.1: Illustration of Top-Down and Bottom-Up Approaches to Clustering.

### 3.1.3 Presentation of the K-Means and Hierarchical Approaches.

Let  $(b_i)_{i \in \{1, \dots, N_b\}}$  be a set of nodes,  $\overrightarrow{LMP}_b$  the vector that contains LMPs at node  $b$ . Let  $N_s$  be the number of considered dispatch scenarios,  $N_b$  the number of buses and  $N_z$  the number of zone inputted by the user. The distance  $d(a, b)$  between nodes  $a$  and  $b$  is defined as the squared Euclidean distance between LMP vectors:

$$d(a, b) = \|\overrightarrow{LMP}_a - \overrightarrow{LMP}_b\|^2 \quad (3.1)$$

The **K-Means algorithm**, as notably described in (Marinho *et al.*, 2017b; Saxena *et al.*, 2017), starts with the random initialization of  $N_z$  cluster centroids  $(cK_i)_{i \in \{1, \dots, N_z\}}$  in the  $N_s$  -dimensional LMP space. Buses are then sorted out according to the closest centroid in the sense of Equation 1, which provides a first grid partition  $(K_i)_{i \in \{1, \dots, N_z\}}$ . Updated cluster centroids are next computed following Equation 2.

$$cK_i = \frac{1}{|K_i|} (\sum_{b \in K_i} \overrightarrow{LMP_b}) \quad (3.2)$$

$$\min \sum_{i=0}^{N_z} \sum_{b \in K_i} dist(b, cK_i) \quad (3.3)$$

The bus sorting and centroid update steps are then repeated so as to reach asymptotic centroids  $(cK_i^*)_{i \in \{1, \dots, N_z\}}$  that minimize the cost function presented in Equation 3. Let  $\varepsilon$  be the error threshold defined by the user. The final grid partition is obtained when the variation of the cost function from an iteration to the next is inferior to  $\varepsilon$ . Figure 3.2 presents the general flowchart of the K-Means algorithm.

As described in (Saxena *et al.*, 2017), K-Medoids and Fuzzy-c-Means can be interpreted as derivatives from the K-Means approach since they are both top-down approaches that rely on bus sorting based on a series of iteratively defined reference points. With the former, cluster centroids are systematically chosen among the input buses, while the latter allows the attribution of buses to multiple clusters during intermediary iterations. In addition to being more straightforward, the K-Means approach is proved more efficient for regarding congestion management than the K-Medoids algorithm in (Marinho *et al.*, 2017b).

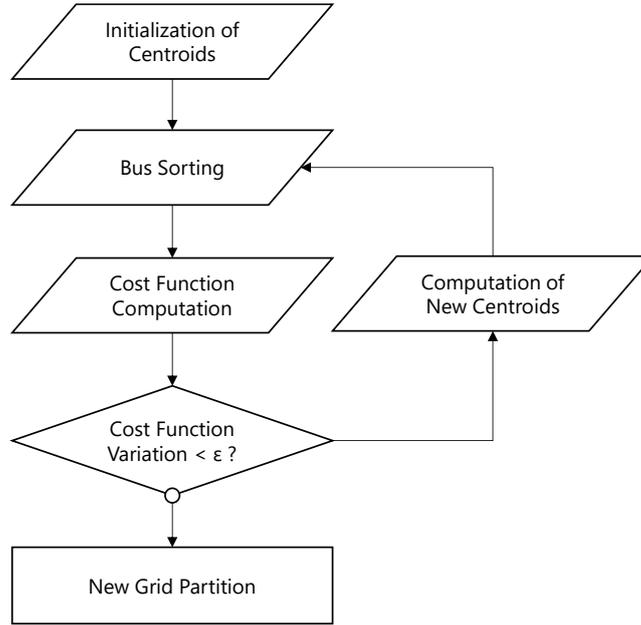


Figure 3.2: K-Means Algorithm Flowchart

As opposed to the random initialization of the K-Means algorithm, which often requires multiple launches in order to secure robust results, the **Hierarchical approach** (Marinho *et al.*, 2017b; Saxena *et al.*, 2017) starts with initializing  $N_b$  single-bus clusters. Closest clusters  $K$  and  $K'$  are then identified according to Equation 4, then merged.

$$\min_{\substack{b_i \in K, b_j \in K' \\ K \cap K' = \emptyset}} \left\| \overrightarrow{LMP}_{b_i} - \overrightarrow{LMP}_{b_j} \right\|^2 \quad (3.4)$$

Cluster mergers are then carried out iteratively until reaching the desired number of zones  $N_z$ , as presented in the flowchart of Figure 3.3.

As pointed out by (Schönheit *et al.*, 2021), **the Hierarchical approach is more straightforward regarding the integration of spatial constraints**, since mergers can be conditioned by node adjacency on the grid. In this work, both clustering frameworks have been first tested on benchmark systems using node adjacency conditions with the Hierarchical approach, and regular LMP-based clustering for the K-Means method (see Section 3.2). Further implementation of spatial constraints have then been examined before extrapolation to a pan-

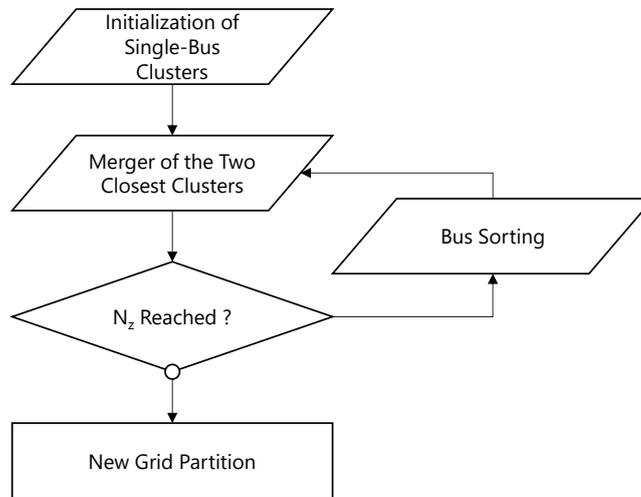


Figure 3.3: Hierarchical Algorithm Flowchart

European grid model in Section 3.3.

## 3.2 RESULTS FROM BENCHMARK SYSTEMS.

As previously discussed, automated grid partitioning offers a great diversity of options regarding clustering algorithms and the associated metrics, parameters and aggregation criteria. Consequently, **we first applied clustering algorithms to benchmark systems** in order to consolidate implementation choices before extrapolation to the European scale.

### 3.2.1 Preliminary Analysis with the NREL-118 Grid Model.

The NREL-118 grid model (Pena, Brancucci and Hodge, 2017), already introduced in Section 2.2, is a benchmark model with high renewable penetration adapted from the IEEE-118 bus test system. Series of locational marginal prices were generated using optimal power flow simulations conducted with Digsilent’s PowerFactory (DigSilent GmbH, 2020). A 13.2 GW load level was used along with twenty representative renewable generation scenarios extracted from 2024 weather projections provided with the model.

Figure 3.4 presents the delineations obtained with hierarchical clustering enhanced with a node adjacency matrix for three to five zones. We identified three main concerns in the light of this first

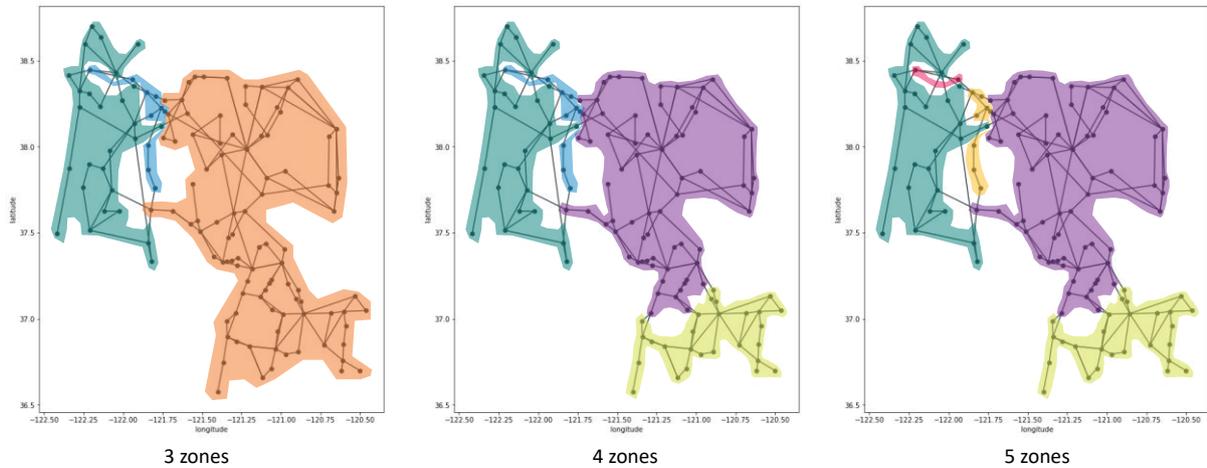


Figure 3.4: NREL-118 Grid Partitioning Using Hierarchical Clustering with Node Adjacency Matrix.

implementation.

#### Problem N°1: Formation of Small Zones.

All three presented delineations lead to the formation of at least one cluster regrouping less than 10% of system buses. We attribute this phenomenon to significantly above average locational marginal prices in this specific area, due to the presence of congestion in the majority of scenarios. However, in the context of European power market dynamics, this may lead to the formation of small clusters around areas with high renewable sources penetration, which are also responsible for extreme price occurrences (Paraschiv, Erni and Pietsch, 2014). **This possibility raises concerns about market liquidity and the relevance of investment signals**, as addressed in (Grimm, Martin, Weibelzahl, *et al.*, 2016).

#### Problem N°2: Choice of the Input Number of Zones.

As previously mentioned, conventional clustering algorithms take the final number of clusters as an input from the user, which raises the question of a stop criteria for the number of zones. In Figure 3.4, the transition from the four-zone to the five-zone delineation consists in splitting the smallest zone in terms of the number of buses. From a

user perspective, this implies finding criteria to find a **balance between the possible benefits of a zone reconfiguration and repeated splittings of specific areas in a given power system.**

### **Problem N°3: Comparison of Obtained Delineations.**

As discussed in Section 3.1, LMP differentials between buses notably reflect congestion phenomena on the grid, which makes LMP-based clustering a good candidate for designing bidding zones that are efficient regarding congestion management. Nonetheless, the diversity of implementation options calls for **criteria to sort out relevant zone delineation candidates** between clustering based grid partitions that may be obtained with different algorithms or even different initialization and settings of a given algorithm.

These three preliminary observations will later be useful in addressing how **preliminary insights on system operation and market efficiency** can be **integrated within the clustering process to design relevant candidate zone delineations.**

#### **3.2.2 Evidences from the 30-Bus Benchmark System**

We used our 30-bus benchmark system, which was introduced in Section 2.2, to first address the design of candidate zone delineations for a given system. As discussed in Section 2.2, the dimensions of this model make it suitable for the benchmark of zone delineation methods, notably through the **easy identification of grid bottlenecks and groups of nodes with similar generation dynamics** (notably fatal generation).

In line with Problem N°3, the most evident distinction criteria between clustering-based delineations must be linked to the **impact of zone reconfiguration on congestion management efforts.** This leads many authors to use redispatching volumes (Egerer, Weibezahn and Hermann, 2016) and costs (Burstedde, 2012; Breuer and Moser, 2014) as post-clustering evaluation criteria. The underlying rationale is to identify zone configurations that minimize corrective congestion management actions, thus narrowing the difference between the zonal dispatch at market closure and the final dispatch that considers all grid constraints.

Nonetheless, as pointed out in (Marinho *et al.*, 2017b), the estimation of redispatching costs and volumes can be computationally challenging and rely on arbitrary cost assumptions. The same authors therefore introduce a **Redispatching Effort index** (RE) that can be computed using only outputs of the zonal and nodal dispatch problem resolution presented in Section 2.1.

Let  $G$  be the set of synchronous generators in the system. Let  $\hat{P}_g$  and  $P_g^*$  be the respective outputs of generator  $g$  in the zonal and the nodal, final dispatch. RE is defined as follows:

$$RE = \frac{\sum_{g \in G} |\hat{P}_g - P_g^*|}{\sum_{g \in G} P_g^*} \quad (3.5)$$

The Redispatch Effort index (RE) therefore **represents the share of redispatched energy over the total energy dispatched for a specific time step**, thus the congestion management effort associated with a given delineation.

Nonetheless, in line with Problems N°1 and N°2, **the sole consideration of redispatching efforts may lead to favour grid partitions with smaller zone** as the system gets closer to nodal operating conditions. In the literature, authors therefore tend to **balance system operation indicators with market efficiency criteria**, *e.g.* market shares per generator type ((Egerer, Weibezahn and Hermann, 2016)) or market concentration ((Breuer and Moser, 2014)).

In this first benchmark step, we introduce an indicator that informs the **size of a given zonal market**, which is a **general indicator for liquidity** and does not require any complementary computational effort. For a given zone  $z$ , zone weight  $W_z$  is set as the lowest value in megawatts between net demand and available generation capacity:

$$W_z = \min \left( \sum_{g \in G_i^{disp}} \bar{P}_g + \sum_{g \in G_i^{fatal}} P_g - Nex_i^-, D_i + Nex_i^+ \right) \quad (3.6)$$

$$Nex_i^+ = \max(Nex, 0)$$

$$Nex_i^- = \min(Nex, 0)$$

Where  $G_i^{disp}$  and  $G_i^{fatal}$  are the respective sets of dispatchable and

fatal generators in zone  $i$ ,  $D_i$  is the zonal demand,  $Nex_i$  the net position,  $\bar{P}_g$  the capacity of generator  $g$  and  $P_g$  the output of generator  $g$  over all scenarios. Zone weight is therefore an indicator for **the capacity of market players to carry out transactions in their zone**, taking into account demand, available generation and the level of interconnection.

The joint monitoring of RE and  $W_z$  is therefore a means to address Problems 1, 2 and 3 insofar as **it reflects the relevance of a given grid partition regarding congestion management while highlighting possible liquidity losses** due to small zone formation as the input number of clusters increases.

We applied these two indicators to grid partitions obtained with Hierarchical and K-Means clustering on the 30-bus benchmark system. Series of optimal power flow simulations were conducted using 300 wind and PV generation scenarios and five demand scenarios from 40 to 80 gigawatts, adding up to 1,500 dispatch configurations. Each OPF simulation is a mixed-integer linear (MILP) optimization problem with 59 variables and 120 constraints, and was computed using Digsilent GmbH's PowerFactory 20.0.3 (DigSilent GmbH, 2020) and an Intel Core 2.70 GHz processor, for an average computing time of 200 milliseconds.

Renewable capacity factors are extracted from the Renewables.ninja online platform (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016; *Renewables.ninja*, 2022) based on experimental observations on French and German renewable fleets. We used K-Means clustering to consolidate 300 renewable generation scenarios based on hourly data from 1985 to 2016.

Figure 3.5 displays the scenario distribution of capacity factors for offshore wind, onshore wind and PV. In particular, these renewable generation represent both daytime and evening hours with half of them corresponding to winter dispatch configurations under the French and German weather conditions. This explains that around half PV generation scenarios correspond to zero or close to zero capacity factors.

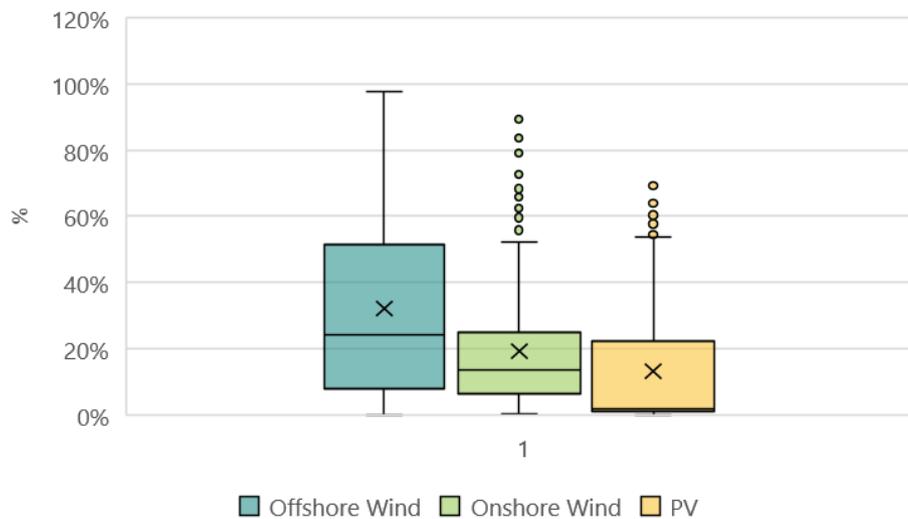


Figure 3.5: Distribution of Renewable Capacity Factors Over 300 Renewable Generation Scenarios

A visualization of the obtained locational marginal prices can be found in Figure 3.6, with average and standard deviation per node. Two main node-behaviours stand out. On the one hand, **groups of nodes with higher, less volatile LMPs, correlated to areas with dominant thermal generation fleets**. On the other hand, **Northern areas with high wind penetration returning lower, more volatile prices**.

As announced at the end of Section 3.2.1, clustering algorithms were first employed with limited implementation of spatial constraints, using a node adjacency matrix for Hierarchical clustering and no further constraint for the K-Means method. In order to counter the effect of random initialization, we carried out series of five launches for K-Means clustering, then chose the most frequent zone attribution of each node. In spite of the random initialization, we obtained the same grid partitions with all five launch for the case presented in Figure 3.8.

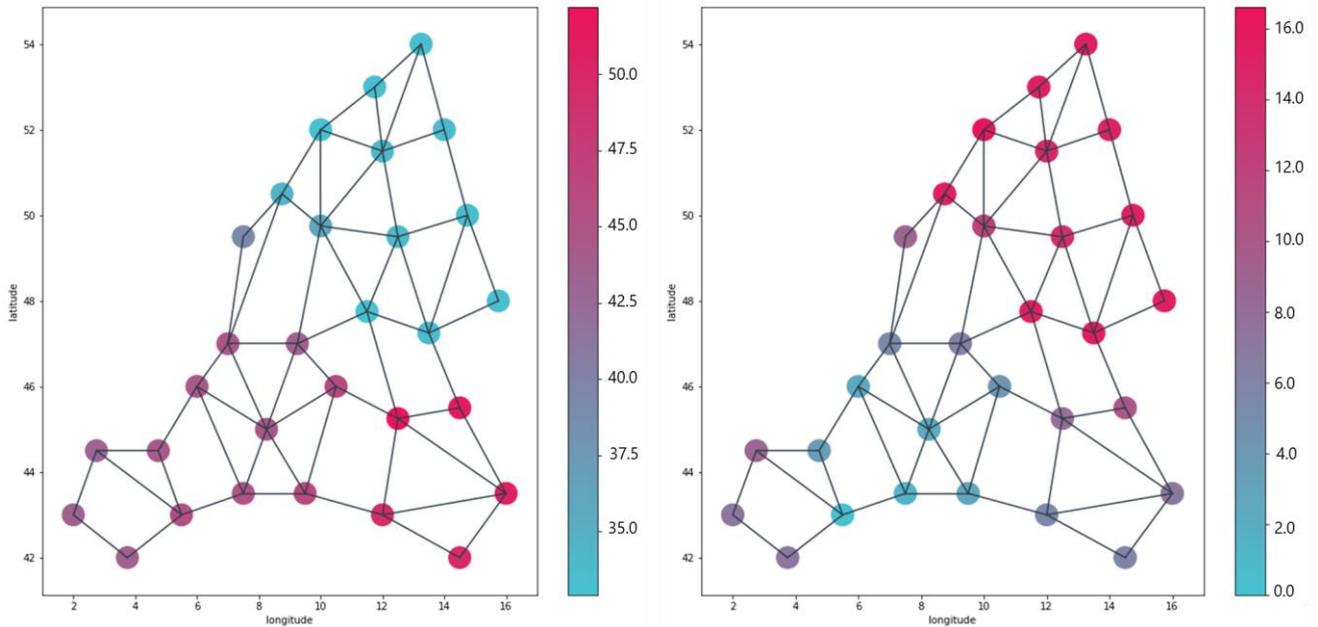


Figure 3.6: Map of Locational Marginal Prices under 300 Scenarios. Average (Left) and Standard Deviation (Right).

Five-cluster grid partitions obtained with Hierarchical and K-Means clustering are presented in Figure 3.7 along with the corresponding evaluation indicators in Table 3.II, as a comparison to the status quo delineation with five zones. K-Means bus clustering turns out to be slightly more efficient in reducing redispatching levels (materialized by the average RE indicator over all scenarios) in comparison to the status quo. This observation echoes the case study carried out in (Marinho *et al.*, 2017b) with the same indicator, where the K-Means approach proves more efficient than Hierarchical clustering on a benchmark case with a single dispatch scenario for Continental Europe, yet less performant on a full multi-scenario approach.

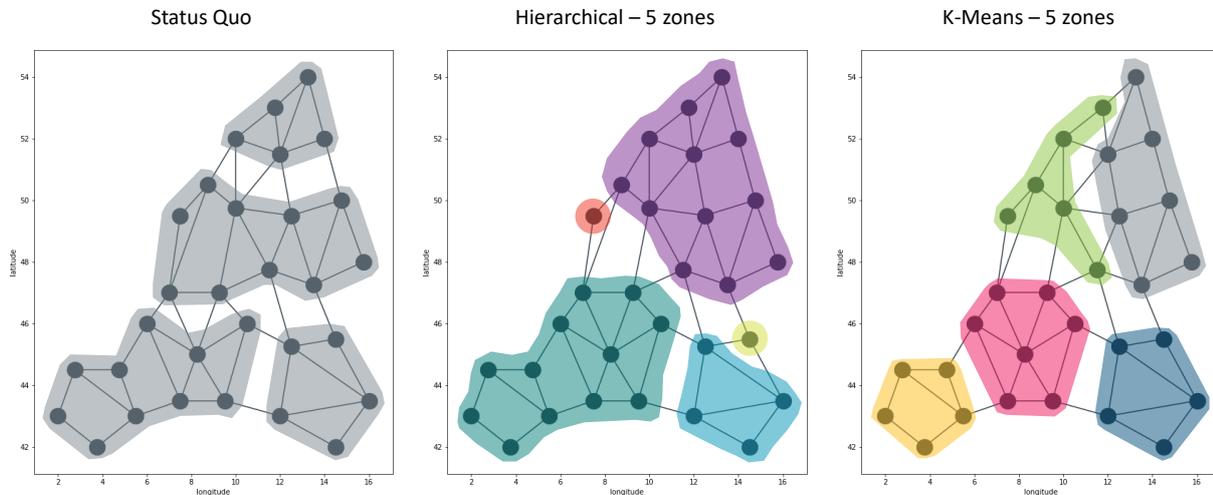


Figure 3.7: Status Quo Delineation and Five-Zone Grid Partitions Obtained with Hierarchical and K-Means Clustering – 30-Bus Benchmark System.

Table 3.II: Evaluation Indicators for Five-Zone Partitions - 30-Bus Benchmark System.

	<i>Status Quo</i>	<i>Hierarchical</i>	<i>K-Means</i>
<b>Av. RE [%]</b>	<b>9.7%</b>	8.1%	7.9%
<b>Min <math>W_z</math> [GW]</b>	<b>8.1</b>	0.83	10

More significantly, it is observed that Hierarchical clustering returns clusters of very heterogeneous sizes, with two single-node clusters in the five-cluster partition. This is confirmed with  $W_z$  as K-Means brings the weight of the smallest zone from 8.1 to 10 GW while Hierarchical clustering makes it drop to 0.83 GW. In terms of the concerns identified in Section 3.2.1, **K-Means clustering is therefore more likely to prevent the formation of small zones** (Problem N°1) in this specific case study. This creates more flexibility to refine the input number of clusters without creating excessively small zones (Problems N° 2-3).

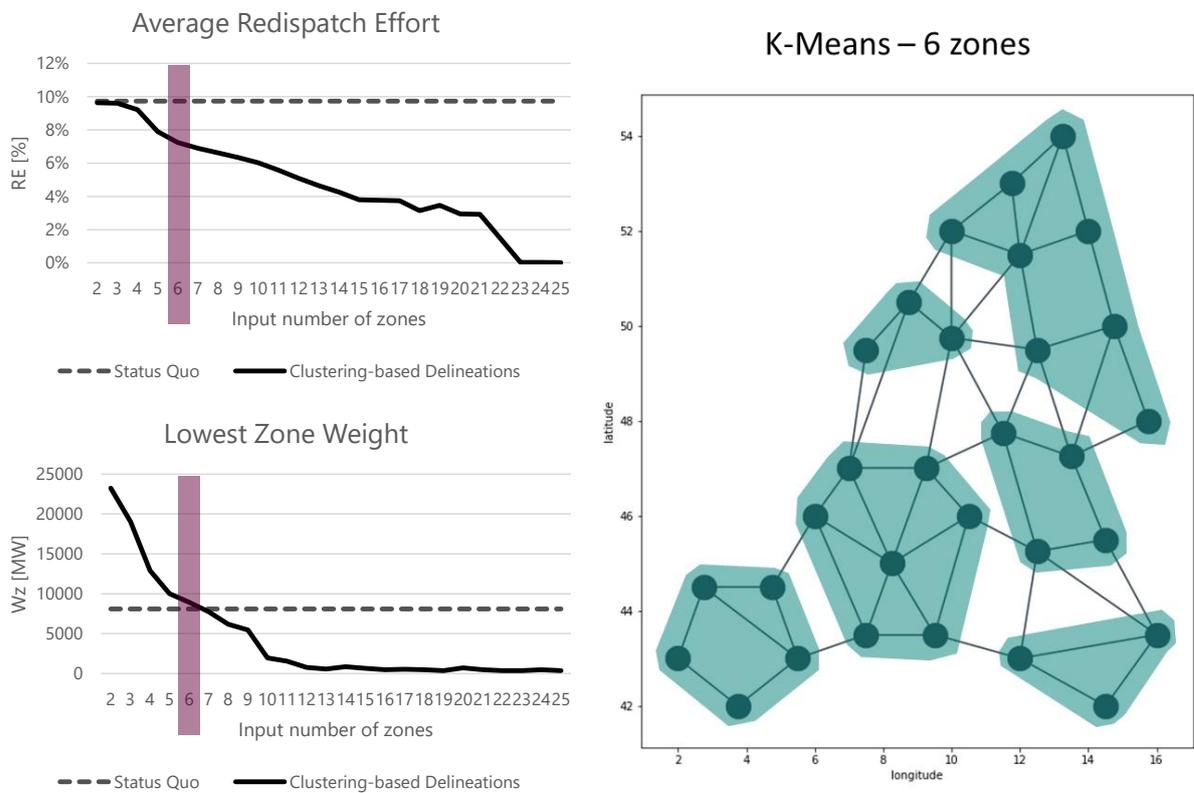


Figure 3.8: RE and Wz Indicators as a Function of the Input Number of Zones with K-Means Clustering (Left). Six-Zone Grid Partition Obtained with K-Means Clustering.

Figure 3.8 shows the **evolution of evaluation indicators with the input number of zones** obtained with K-Means clustering. As expected, the average redispatching level over all scenarios tends to decrease with the number of zones, while minimum zone weights plummet quickly when the system gets divided into more zones. In light of these results, a six-zone partition of the system with K-Means clustering can be seen as **an efficient compromise that offers the biggest reduction of RE levels while not decreasing minimum zone weight** in comparison to the status quo delineation.

This candidate six-zone configuration is also presented in Figure 3.8. Interestingly, we notice the creation of two three-node zones that correspond to the highest installed renewable capacities, with respectively wind power in the North and PV in the South.



### 3.3 EXTRAPOLATION TO BIDDING ZONES OF THE EUROPEAN POWER SYSTEM

As detailed in Section 2.3, our European grid model comprises around 2,700 bus and a status quo configuration with twenty-three zones. In this context, balancing the RE indicator with zone weights under every possible input number of zones is not as relevant since this does not guarantee that clustering-based delineations are spatially coherent and suitable for real-life implementation. In this section, we generally show how **integrating spatial constraints into clustering processes** allows the formation of **candidate delineations that are illustrative of conventional zone reconfiguration patterns**, which is not only a matter of addressing the optimal input number of zones.



Figure 3.9: Status quo (current) delineation.

#### 3.3.1 Enhancement of Clustering Methods

The European static grid model featured in this case study was introduced in Section 2.3.2, and is notably aligned with the 2025 system projection of the “National Trends” scenario from ENTSO-E’s TYNDP 2020 (ENTSO-E, 2021d). The status quo zone configuration, which mostly corresponds to national borders of the EU Member States, is presented in Figure 3.9.

In line with the approach presented in (Marinho *et al.*, 2017b), we used the redispatch effort (RE) index to identify clustering-based grid partitions that are efficient from a congestion management point of view. Nonetheless, in the context of European bidding zones, **the heterogeneity of status quo zone sizes is mostly inherited from historically national power system developments**. Pure application of a zone weight criteria, as explored with the 30-bus benchmark system, therefore becomes less relevant.

Instead, the judicious integration of geographical coordinates into clustering processes is the avenue we chose in order **to secure both the relative homogeneity of zone weights and the overall readability of alternative zone borders**. In particular, this approach tends to mitigate the isolation of buses with extreme LMP values by making them more likely to be integrated in the same cluster as geographically close buses. In that sense, it is notably meant to limit the split of smaller bidding zones.

Let  $(\vec{x}_{b_i})_{i \in \{1, \dots, N_b\}}$  be the geographical coordinates of the  $N_b$  buses. Let  $w_x$  and  $w_{LMP}$  be scalar such that

$$w_x + w_{LMP} = 1 \quad (3.7)$$

For each bus, we define a spatially weighted LMP vector such that:

$$\vec{LMP}'_{b_i} = \begin{pmatrix} \sqrt{w_{LMP}} \cdot \vec{LMP}_{b_i} \\ \sqrt{w_x} \cdot \vec{x}_{b_i} \end{pmatrix}; \forall i \in \{1, \dots, N_b\} \quad (3.8)$$

The squared Euclidean distance between two buses thus observes the following identity:

$$\begin{aligned} \text{dist}(\vec{LMP}'_A, \vec{LMP}'_B) &= w_{LMP} \cdot \text{dist}(\vec{LMP}_A, \vec{LMP}_B) \\ &+ w_x \cdot \text{dist}(\vec{X}_A, \vec{X}_B) \end{aligned} \quad (3.9)$$

We therefore base our analysis on three clustering methods, each involving weights  $w_x$  and  $w_{LMP}$ :

- 1) A geographically weighted K-Means approach (**wK**).
- 2) A geographically weighted hierarchical approach (**wH**).
- 3) An enhanced version of the wH method with the additional input of a connectivity matrix, resulting in a “connected” wH approach (**c-wH**).

This implementation of spatial coordinates is convenient insofar as it allows **similar adaptations for both the K-Means and the Hierarchical algorithm**, respectively with the wK and wH methods. The use of geographical coordinates is also deemed relevant in (Chavent *et al.*, 2018). The addition of a connectivity matrix in the c-wH approach nonetheless echoes the methodologies presented in (Felling and Weber, 2018; Colella *et al.*, 2021; Schönheit *et al.*, 2021). In (Colella *et al.*, 2021), series of bus partitions resulting from LMP-based K-Means and Hierarchical clustering on single dispatch scenarios. Bus adjacency solely intervenes in a post-processing step involving spectral clustering. We therefore prioritized the single-step, straightforward approach of (Felling and Weber, 2018; Schönheit *et al.*, 2021) in order to compare the inherent performance of K-Means and Hierarchical approaches when it comes to zone delineation.

LMP vectors were computed based on 600 dispatch scenarios for the year 2025, using both winter and summer load scenarios from “National Trends” scenario in ENTSO-E’s TYNDP 2020 (ENTSO-E, 2020d) and national RES generation capacity factors extracted from the Renewables.ninja database (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016; *Renewables.ninja*, 2022). In particular, we used **two batches of 300 renewable capacity factor scenarios, respectively representing winter and summer generation levels, in combination with a winter and a summer peak demand point** extracted from TYNDP data. The distribution of the 600 renewable capacity factor scenarios as well as the demand levels are presented on Figure 3.10 for the 12 main modelled bidding zones. The same scenarization approach was used for peripheric bidding zones.

Each DC-OPF is a mixed-integer linear optimization problem with approximately 5,500 variables and 11,200 constraints. Digsilent GmbH's PowerFactory 20.0.3 (DigSilent GmbH, 2020) was used, combined with an Intel Core 2.70 GHz processor. The average computing time per scenario was 62 seconds. Clustering methods were carried out with support of the Scikit-learn package on Python 3.7.4 (Pedregosa *et al.*, 2011).

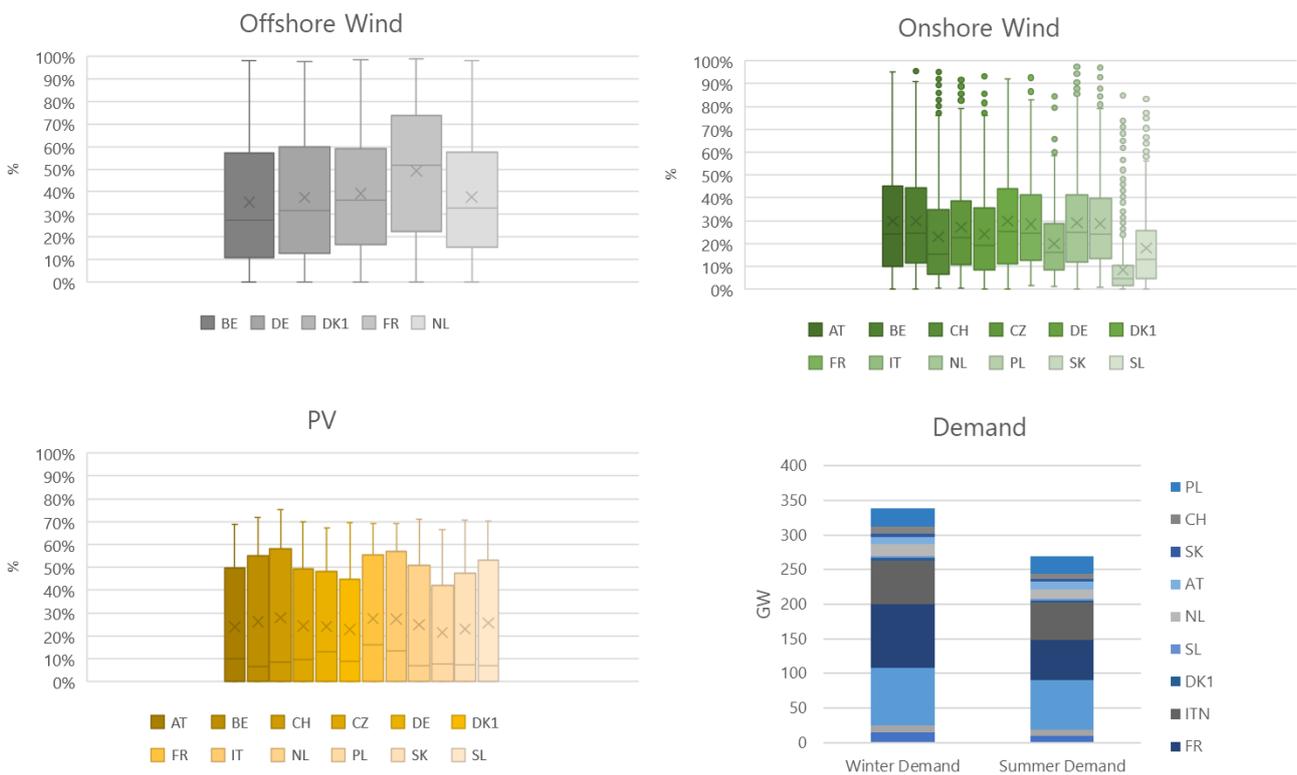


Figure 3.10: DC-OPF Scenarios for Main Modelled Bidding Zones. Distribution of Renewable Capacity Factors and Demand Levels.

Figure 3.11 presents the grid partitions obtained with the c-wH method and various values for LMP weight  $w_{LMP}$ . On the one hand, **sole consideration of LMPs ( $w_{LMP} = 1$ ) may produce spatially heterogeneous clusters that are highly decorrelated from administrative borders.** In addition to liquidity concerns regarding the formaton of small zones, this could undermine the suitability of resulting delineations for real-life implementation. On the other hand,

we needed to **make sure that  $w_{LMP}$  was high enough to secure benefits from a congestion management point of view.**

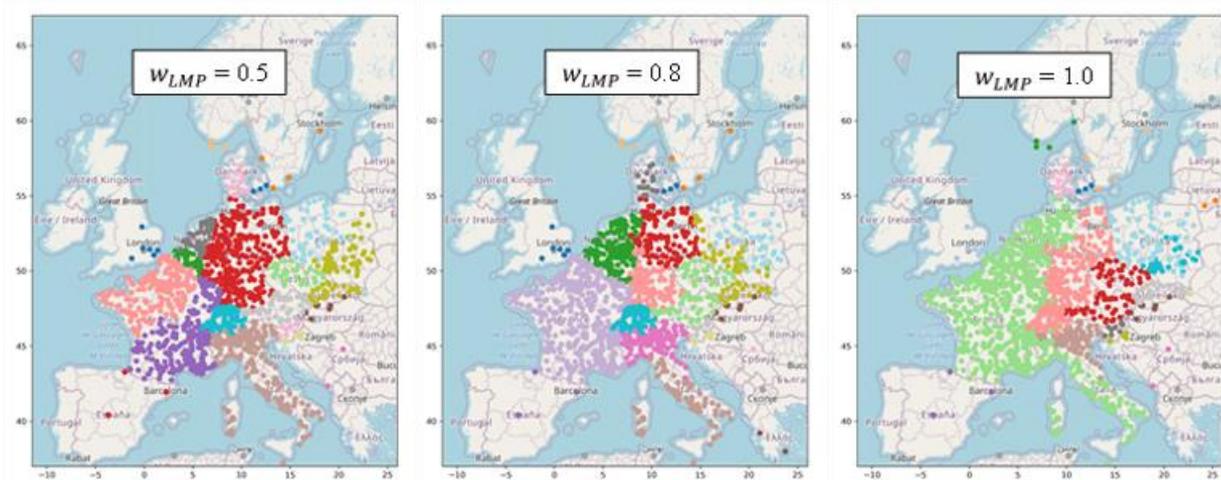


Figure 3.11: Clustering results for different values of  $w_{LMP}$ .(c-wH method).

[Map source : [openstreetmap.fr](https://openstreetmap.fr)]

We used the redispatch effort (RE) criterion to investigate LMP weightings that **efficiently reduce redispatching needs while preserving geographical relevance**. In this context of Pan-European simulations, our objective is neither to identify the best bus clustering method nor to determine an optimal number of zones. On the contrary, our goal was to **generate a series of alternative Pan-European zone configurations obtained with our three clustering approaches articulated with different input zone numbers**. The use of the  $W_z$  indicator as a complement to the RE index was therefore deemed irrelevant.

We therefore applied the three clustering methods to LMP series obtained with our 600 dispatch scenario for a 2025 horizon, using six levels of  $w_{LMP}$  weightings and for an input number of 23 zones – same as the Status Quo configuration. A merit order algorithm was then applied to determine the resulting zonal dispatches, of which we deduced average RE levels.

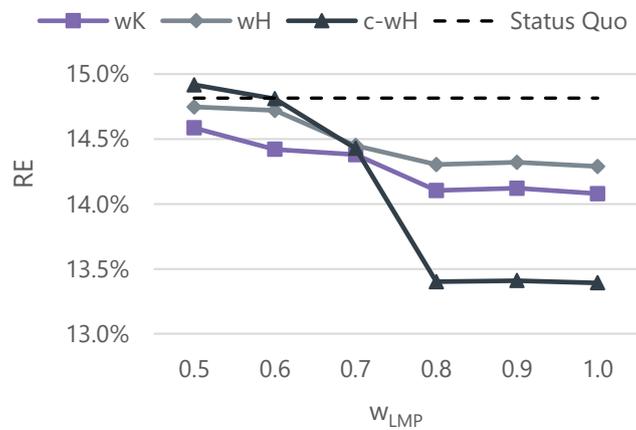


Figure 3.12: RE values as a function of  $w_{LMP}$  and clustering method.

**Results presented in Figure 3.12 suggest that a  $w_{LMP}$  value of 0.8 offers the full potential of RE reduction while maximizing  $w_x$ .** Moreover, the connected, weighted Hierarchical approach (c-wH) particularly stands out from both weighted Hierarchical (wH) and weighted K-Means (wK) methods. However, in comparison to the status quo delineation, c-wH clustering fails to reduce the overall RE level of the system for any  $w_{LMP}$  value lower than 0.6, due to the redundant enforcement of the bus adjacency matrix and weighted spatial coordinates.

**This adaptation step illustrates the extreme sensitivity of model-based grid partitions to the chosen clustering methods and parameters.** The sole criteria of improving congestion management – which is the main motivation behind the use of LMP-based clustering – may therefore prove insufficient as to design consensual delineations, possibly leading to arbitrary decisions. In particular, **including an exploratory step to optimize the implementation of spatial constraints can help designing grid partitions that are illustrative of more relevant reconfiguration patterns.**

### 3.3.2 Design of Candidate Bidding Zone Delineations

We used our three clustering methods to generate candidate European zone delineations based on the previously mentioned 600 DC-OPF simulations for the year 2025. Based on findings from Section 3.3.1, the  $w_{LMP}$  weight was set to 0.8.

**Evidence from the literature show no consensual approach to defining the input number of zones.** Burstedde et al. (Burstedde, 2012) base their choice on the statistical distribution of LMPs within each cluster for the CWE region, which leads to selecting a six-zone and a nine-zone delineation for the year 2015, yet a five-cluster and a nine-cluster partition for 2020 scenarios. Breuer and Moser (Breuer and Moser, 2014) examine ten possible number of clusters for Continental Europe, from one to twenty. This echoes several contributions that choose to explore a vast array of input numbers, such as Marinho et al. (Marinho *et al.*, 2017b) who explore their RE redispatch index on a full range from one to one hundred clusters in Continental Europe and Colella et al. (Colella *et al.*, 2021) who examine from two- to seven-zone configurations in Italy. Finally, Felling and Weber (Felling and Weber, 2018) mostly focus on five-zone delineations for CWE, yet also explore intrazonal and cross-zonal price variability from one single to two thousand zones.

In order to generate **comparable yet diverse candidate zone delineations**, we decided not to focus on specific zone numbers but on general reconfiguration trends. These are not to be considered as formal zone revision proposals, but as illustrations for **regularly promoted reconfiguration patterns**. Starting from the status quo number of twenty-three zones in our model, **we gradually increased the number of zones as to obtain specific reconfiguration stages:**

- **Zone Shuffle:** the number of zones remains unchanged.
- **Big Country Split:** the number of zones is increased until big countries are split in at least two bidding zones. This is reached with requesting three more zones using wK and c-wH, and four with the wH method. This zone revision pattern is inspired by

expert-based delineations examined in ENTSO-E's First Edition of the Bidding Zone Review (ENTSO-E, 2018b).

- **Regionalized System:** the number of zones is increased until big countries are split in at least three bidding zones. This is achieved with respectively seven, six and nine additional zones using wK, wH and c-wH. This pattern echoes contributions that address the impacts of a major increase of the number of bidding zones in Europe, such as (Breuer and Moser, 2014; Van Den Bergh *et al.*, 2016; Marinho *et al.*, 2017b; Felling and Weber, 2018).

A post-processing step is then performed in two steps. First, we remove zone splitting in peripheral bidding zones that are not extensively represented in our model. Then, we reverse shiftings of less than 10% of buses from a given country to a foreign zone. This second step is a direct adaptation of the post-processing rules that were used on model-based scenarios of ENTSO-E's First Edition of the Bidding Zone Review (ENTSO-E, 2018b). In particular, this allows a general fitting of zone borders to closely national borders.

**We therefore studied nine zone configurations**, corresponding to the three versions of each revision trend obtained with each clustering method. These are presented in Figure 3.13.

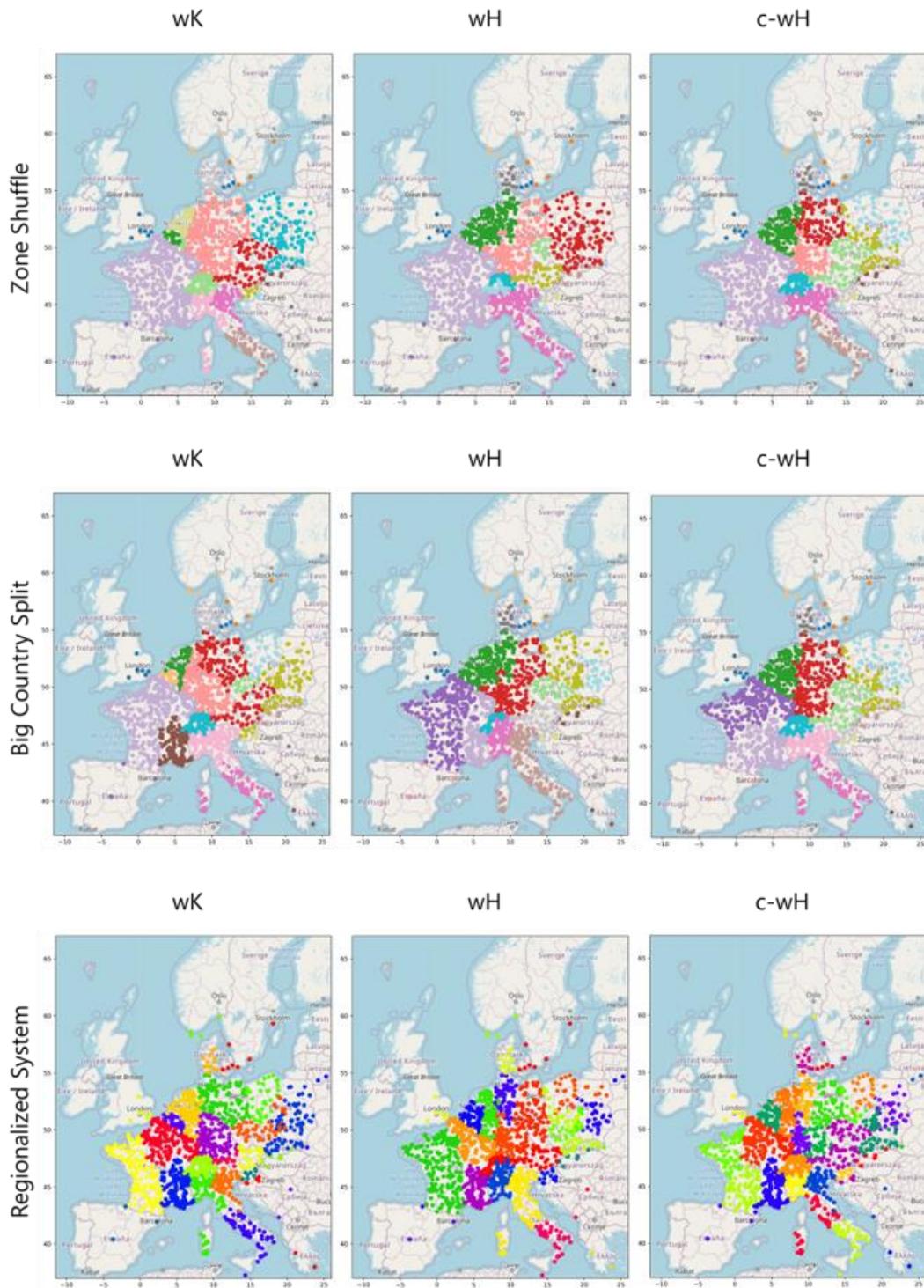


Figure 3.13: Candidate Model-Based Delineations for European Bidding Zones.



## KEY FINDINGS – CHAPTER 3

In this chapter, we focus on how conventional data partition algorithms can be adapted to the design of European bidding zone revision scenarios that are geographically relevant and efficient from a congestion management perspective.

After a literature review of bus selection criteria and algorithms, **we identified general concerns regarding the use of conventional approaches to LMP-based clustering**, including Hierarchical and K-Means algorithms. In particular, the risk of creating small bidding zones with poor market liquidity, the choice of an input number of zones and the ability to identify grid partitions that are relevant in terms of congestion management – since it is the main motivation for LMP-based clustering – appeared to be specifically challenging.

The identification of these concerns brought up the necessity to introduce a metrics for redispatching efforts, balanced with other criteria that preserve zone size. This is achieved on our 30-bus benchmark system by introducing a zone weight index to **identify zone reconfigurations that reduce redispatching but also secure the general level of market liquidity in each zone.**

At a more realistic pan-European scale, the sheer notion of zone weight is not sufficient to secure the formation of geographically relevant clusters. **Our main contribution was therefore to introduce a weighting system between locational marginal prices and spatial bus coordinates**, that we specifically pondered according to our static grid model using the previously mentioned redispatch effort index. This **model-specific adaptation step** is useful to address the extreme sensitivity of clustering-based zone grid partitions to algorithm choice and settings.

This enhancement of clustering algorithms with spatial constraints allowed us to generate candidate delineations for European bidding zones. **We identified three general zone revision patterns observed in the literature and institutional contributions to the topic**, and illustrated these patterns with grid partitions obtained with three distinct clustering approaches.

While this chapter addresses the use of clustering algorithms and how to enhance them for automated bidding zone delineation, the obtained candidate delineations are first of all **a base for developing an extensive assessment methodology in the next two chapters**. The methodologies presented in Chapters 4 and 5 notably aim at presenting a multidimensional diagnosis that articulates congestion management, generation dynamics, price formation, investment signals and structural economic transfers between producers, consumers and transmission system operators on a 2025, 2030 and 2040 basis.

## 4 ASSESSING CANDIDATE ZONE DELINEATIONS

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In this chapter, **we focus on indicators and methodologies to assess the overall performance of a given zone delineation.** We gradually develop an approach that combine system operation, market efficiency and the relevance of specific zone scenarios regarding short- to long-term evolutions of the power system. In contrast to Chapter 3 where we presented the integration of techno-economic criteria into automated grid partitioning, we hereby address the **assessment of previously built alternative zone configuration scenarios.**

As discussed in previous chapters, institutional approaches to bidding zone revisions are **highly motivated by the perspective of maximizing cross-zonal exchanges**, notably targeting more efficient congestion management concerns. Nonetheless, in line with preliminary stakeholder consultation and criteria required by the *Capacity Allocation – Congestion Management* network code (European Commission, 2015), the ENTSO-E’s First Edition of the Bidding Zone Review (ENTSO-E, 2018b) features a multidimensional evaluation grid with nineteen items sorted into three categories (see Table 4.1): *Network Security*, *Market Efficiency* and *Stability and Robustness of Bidding Zones*. In compliance with the CACM network code, this evaluation grid will also intervene in upcoming steps of the current Bidding Zone Review Process (ACER, 2020a).

As a matter of fact, this evaluation grid combines system operation and market efficiency criteria through referring to indicators that are recurrent in both industrial and academic publications. While it is not used at such in the present work, it further legitimates our commitment to a **multi-dimensional approach that involves related or sometimes overlapping indicators.** Furthermore, we hope to contribute to **better multi-horizon consideration of the identified evaluation axes**, which has not been fully explored in previous Bidding Zone Review efforts.

Table 4.I: Evaluation Criteria from ENTSO-E's First Edition of the Bidding Zone Review.

Network Security	Market Efficiency	Stability and Robustness of Bidding Zones
Operational Security	Economic efficiency	Stability and robustness of bidding zones
Security of Supply	Firmness costs	Consistency across capacity calculation time frames
Degree of uncertainty in cross-zonal capacity calculation	Market liquidity	Assignment of generation and load units to bidding zones
	Market concentration and market power	Location and frequency of congestion (market and grid)
	Effective competition	
	Price signals for building infrastructure	
	Accuracy and robustness of price signals	
	Long-term hedging	
	Transition and transaction costs	
	Infrastructure costs	
	Market outcomes in comparison to corrective measures	
	Adverse effects of internal transactions on other bidding zones	
	Impact of the operation and efficiency of the balancing mechanisms and imbalance settlement processes	

Furthermore, the CACM criteria are **not necessarily mutually exclusive**, with the examples of *Economic efficiency*, *Market competition and market power* and *Effective competition*. Moreover, they **did not systematically lead to quantitative assessment** in the First Bidding Zone Review, like the *Transition and transaction costs* dimension. From a more methodological point of view, **they may sometimes be hard to qualify with the conventional modelling frameworks** discussed in Section 2.1. In fact, the evaluation of some of these criteria in academic works tend to involve computationally demanding modelling frameworks. Let us notably mention the enhancement of the unit commitment problem to address reserve coordination in (Koltsaklis and Dagoumas, 2018), nonlinear optimization for evaluating uncertainty in capacity calculation in (Grimm, Martin, Weibelzahl, *et al.*, 2016), or econometrics-oriented approaches to study hedging in forward markets in (Bevin-McCrimmon *et al.*, 2018).

Moreover, this evaluation grid and the newer methodology proposed

in by ACER in 2020 (ACER, 2020a) have raised **concerns from market participants and stakeholders** regarding the quantification of transition costs, impacts on market efficiency and investment signals (Eurelectric, 2020).

In this work, we focus on **indicators that can be computed through conventional economic dispatch simulations** such as optimal power flow and unit commitment. **We specifically address the robustness of these indicators over time**, introducing dispatch scenarios for 2025 to 2040 horizons. In particular, the interest of integrating a robustness analysis is **both to secure a stable market design that is suitable for long-term grid and low-carbon generation investments and to avoid recurrent restructuring leading to additional transition costs.**

Section 4.1 reviews the evaluation indicators that are available from the literature and institutional documentation. We therefore conduct a first assessment of the performance of clustering-based bidding zones over time based on our 30-bus benchmark system in Section 4.2. We then extrapolate these first evidences using our pan-European grid model, featuring candidate zone delineations from Section 3.3.2.



## 4.1 A REVIEW OF COMMON ASSESSMENT INDICATORS

In this section, we review conventional options for the evaluation of a given zone delineation, with a multi-dimensional focus on system operation and market dynamics. Our indicators are therefore selected and enhanced based on academic contributions and reference institutional exercises like the current Bidding Zone Review (ACER, 2020b) or international examples for market reporting (California ISO, 2019; Commission de Régulation de l'Énergie, 2019; Monitoring Analytics LLC, 2020).

We prioritized **indicators that illustrate the dynamics of the pan-European power system as a whole**, without focusing on specific areas. Their choice and design is also motivated by **how straightforward their computation is regarding the simulation chain presented in Chapter 2**. Chapter 5 will later complement this analysis with the consideration of market and investment dynamics in order to discuss the impact of zone reconfiguration on system trajectories.

### 4.1.1 System Operation

As discussed in previous chapters, congestion management is a central topic regarding bidding zone review efforts. In particular, **the design of congestion-compliant zone delineations is the main rationale behind the use of LMP-based clustering**. In the literature, many contributions have therefore addressed the efficiency of congestion management under a given combination of market design, corrective measures and overall dispatch conditions. A review of the evaluation criteria employed in sixteen references is available in Table 4.II.

Our first observation from that review is that congestion phenomena are not so much considered for their pure physical manifestation, i.e. in terms of line flows and capacity limitation. Two types of indicators stand out instead. On the one hand, contributions tend to address **the level of necessary corrective actions in a given dispatch configuration**. These actions may be specific to congestion management, such as redispatching and countertrading, or more circumstantial, like RES curtailment. On the other hand, authors tend

to assess the **system-wide economic impacts of congestion management doctrines**, analyzing overall system and congestion costs, generation levels and producer revenues, as well as market efficiency and price formation.

Table 4.II: A Review of Evaluation Criteria for Congestion Management.

Ref.	Redispatching/ Countertrading Costs and Volumes	RES Curtailment	Line Flows	Exchange Capacity Limitations	Adequacy Failures	System/ Congestion Cost	Price Formation/ Market	Generation /Producer Revenue	GHG Emissions
(Huang, Bompard and Yan, 2011)	✓						✓	✓	
(Dijk and Willems, 2011)							✓		
(Breuer <i>et al.</i> , 2011)	✓		✓						
(Singh and Parida, 2013)				✓	✓	✓			
(Sarfati and Hesamzadeh, 2013)						✓	✓	✓	
(Oggioni and Smeers, 2013)						✓	✓	✓	
(Delgadillo and Reneses, 2013)	✓		✓				✓	✓	
(Singh, Mahanty and Singh, 2015)	✓				✓			✓	
(Reza Salehizadeh, Rahimi-Kian and Oloomi-Buygi, 2015)						✓		✓	✓
(Higgins <i>et al.</i> , 2015)	✓	✓				✓	✓	✓	
(Kunz and Zerrahn, 2015)	✓	✓				✓			
(Schermeier, Vergara and Fichtner, 2018)		✓							
(Prajapati and Mahajan, 2021)			✓		✓	✓		✓	
(Pantoš, 2020)	✓								
(Narain, Srivastava and Singh, 2020)	✓	✓							
(Diop, 2020)	✓			✓					
<b>Count</b>	<b>9</b>	<b>4</b>	<b>3</b>	<b>2</b>	<b>3</b>	<b>7</b>	<b>6</b>	<b>8</b>	<b>1</b>

In the literature dedicated to congestion management, operational aspects are intertwined with or even sometimes supplanted by analyses of market operation or system costs and revenues. Nonetheless, **in the academic coverage of a revision of European bidding zones, system operation indicators are often examined without thorough economic assessment.**

In (Burstedde, 2012), Burstedde et al. conduct a joint analysis of redispatching costs, average prices and total system costs over the

Central western Europe perimeter. In (Breuer and Moser, 2014), Breuer and Moser evaluate clustering-based zone delineations through a monitoring of the generation and redispatch costs aggregated over Continental Europe. Van den Bergh et al. (Van Den Bergh *et al.*, 2016) mostly focus on the effect of zone revision in Central Europe on the probability of line overloads and the annual generation of thermal generation technologies. These first examples reflect **cases where a market-oriented analysis complements the system operation approach**, yet with less extensive characterization than general contributions on congestion management (see Table II).

However, **in a number of contributions, the operational perspective is clearly the prevalent evaluation criteria**: this is the case with the measure of the redispatch effort in (Marinho *et al.*, 2017b), or contributions that evaluate the dispersion of locational marginal prices ((Felling and Weber, 2018; Colella *et al.*, 2021)) and power transfer distribution factors (Colella *et al.*, 2021) within clustering-based zones – which is also a criteria motivated by congestion management.

On the other hand, some authors conduct **more multidimensional analyses, yet on more restrained areas of the European Power System**. This is often the case with contributions considering a North-South split of the German bidding zone. In (Egerer, Weibezahn and Hermann, 2016), Egerer and al. analyze redispatching volumes and average electricity prices per zone, but they also integrate the impacts of zone splitting on the market penetration of thermal and renewable technologies, as well as market indicators involving consumer rents, producer profits and congestion rents. A similar zone reconfiguration is explored in (Plancke, De Jonghe and Belmans, 2016), but Plancke et al. mostly focus on price divergence between North and South, and the impact of zone splitting on consumer surplus and commercial exchanges in neighbour countries.

At first, it therefore seems that **the operational impacts of a given zone configuration on congestion management are generally addressed through a limited number of traditional indicators**. In that sense, the redispatch effort index (RE) from (Marinho *et al.*, 2017b) and presented in Section 3.2.2 is a good candidate for synthesizing the

performance of system operation in the remainder of this work.

Nonetheless, a more extensive literature review shows **that system operation indicators are often complemented with an analysis of market efficiency and economic transfers** between producers, consumers and transmission system operators. These dimensions will thus be approached in the remainder of Section 4.1.

#### 4.1.2 Distribution of System Costs and Revenues

As detailed in Section 4.1.1, contributions on congestion management and bidding zone revision frequently integrate an assessment of the impact of bidding zone revision on the **cost of electricity supply** ((Burstedde, 2012; Oggioni and Smeers, 2013; Egerer, Weibezahn and Hermann, 2016; Prajapati and Mahajan, 2021)). This is often associated with an analysis of **generation revenues** ((Huang, Bompard and Yan, 2011; Oggioni and Smeers, 2013; Sarfati and Hesamzadeh, 2013; Breuer and Moser, 2014; Egerer, Weibezahn and Hermann, 2016; Prajapati and Mahajan, 2021)), **consumer surplus** ((Huang, Bompard and Yan, 2011; Oggioni and Smeers, 2013; Plancke, De Jonghe and Belmans, 2016)), and **congestion rents** ((Oggioni and Smeers, 2013; Plancke, De Jonghe and Belmans, 2016)).

This complementarity suggests **a specific concern regarding the distribution of system costs and revenues between** main actors in the power system, namely **producers, transmission system operators and consumers**. In this section, we describe the main cost and revenue dynamics regarding these actors, introducing a method **to track down structural economic transfers resulting from bidding zone revision**. In particular, while a transition of market design may unleash more efficient economic dispatches at market closure in the short run, the counterpart lies in **long-lasting redistributive effects** that notably impact the costs perceived by consumers.

Let  $G, S$  be the respective sets of synchronous and static generators in the system. Let  $c_g, \hat{P}_g, P_g^*$  be the respective marginal cost, dispatch from zonal market closure and final dispatch of generator  $g$ . **The marginal cost of the system** for a given time  $t$  is as follows:

$$C_{sys} = \sum_{g \in G} c_g P_g^* \quad (4.1)$$

Let  $Z$  be the set of zones in the system. We define  $\delta_{z,g}$  such that  $\delta_{z,g}$  equals 1 if generator  $g$  is in zone  $z$ , and 0 otherwise. Let  $p_z$  be the zonal price in zone  $z$  at time  $t$ . Under a pay-as-cleared system, **producer margin** is therefore defined as follows:

$$\Pi_{prod} = \sum_{(z,g) \in Z \times (G \cup S)} \delta_{z,g} p_z \hat{P}_g - C_{sys} \quad (4.2)$$

The margin perceived by producers therefore depends from the amendments in generator outputs requested by transmission system operators to account for grid constraints, i.e. the **cost of redispatching**:

$$C_{redisp} = \sum_{g \in G} c_g (\hat{P}_g - P_g^*) \quad (4.3)$$

From the TSO perspective, the main source of income corresponds to **congestion rents** resulting from price differentials between zones. An illustration of gross congestion rents and how they can be a financial lever for grid reinforcement is provided in Section 1.1. Let  $NEx_z$  be the net position of zone  $z$  at time  $t$ , i.e. the differential between outgoing

and incoming flows. The gross congestion rent perceived by TSOs in the system writes:

$$Y_{TSO} = \sum_z p_z NEx_z \quad (4.4)$$

This can therefore be translated into a **net congestion rent** by deducting redispatching costs:

$$\overline{Y_{TSO}} = Y_{TSO} - C_{redis} \quad (4.5)$$

Finally, the consumers therefore pays for the sum of the producers' profit and the net congestion rent, which leads to the following **consumption cost**:

$$C_{cons} = \sum_{(z,g) \in Z \times (GUS)} \delta_{z,g} p_z \hat{P}_g + \overline{Y_{TSO}} \quad (4.6)$$

Using Equation (4.2), we then obtain the following:

$$C_{sys} = C_{cons} - \overline{Y_{TSO}} - \Pi_{prod} \quad (4.7)$$

Under the assumption that the uncertainty regarding cross-zonal capacity calculation is low, we consider that corrective actions such as redispatching brings final marginal system costs to the optimal value  $C_{sys}$ , which does not depend on the zonal configuration, **the quantity**

$C_{cons} - \overline{Y}_{TSO} - \Pi_{prod}$  is therefore identical under any bidding zone delineation. It is also known from previous chapters that bidding zone reconfiguration affects redispatching costs and therefore congestion rents. Consequently, **the joint monitoring of  $(\overline{Y}_{TSO}, \Pi_{prod}, C_{cons})$  appears reflective of the structural economic transfers between producers, TSOs and consumers in case of a bidding zone revision.**

While these transfers can be punctually managed by adapting regulatory transmission tariffs, structural increases of transmission rents are most of all an incentive to grid reinforcement and have a direct impact on consumption costs.

#### 4.1.3 Market Efficiency and Price Formation

The “Capacity Allocation – Congestion Management” network code (European Commission, 2015), which framed most of the evaluation grid for both Bidding Zone Review methodologies (ENTSO-E, 2018b; ACER, 2020a), promotes specific criteria regarding market efficiency, among which “market liquidity”, “market concentration and power”, and “effective competition”. This relates to traditional economic standards regarding competitive price formation, often illustrated by the use of indicators like the Herfindal-Hirschmann Index (HHI) or the Residual Supply Index (RSI).

Although seldomly used in academic contributions on bidding zones (Breuer and Moser, 2014), these indexes are quite widespread when it comes to institutional market reporting: the RSI is featured in California ISO’s and PJM’s annual market reports (California ISO, 2019; Monitoring Analytics LLC, 2020), while the HHI is also used by PJM and several European energy regulators (Commission de Régulation de l’Énergie, 2019; Monitoring Analytics LLC, 2020). However, Pham notes in (Pham, 2015) that **idiosyncrasies of the electricity industry as well as social and political concerns make the detection of market power particularly difficult**, which fails standard definitions and indicators. They also note that the competition in wholesale electricity markets is **closely monitored at a national level** with dedicated regulatory frameworks like the French “Accès Régulé à l’Électricité

*Nucléaire Historique*". At a European level, concerns on market power also motivate the Regulation on wholesale energy market integrity and transparency (European Parliament and European Commission, 2011),.

From a modeling point of view, **market concentration and power are therefore uneasy to properly qualify at a Pan-European scale and with conventional simulation frameworks**. In this work, we consequently focus on two main dimensions: **market liquidity and price signals**.

A zone weight  $W_z$  indicator was introduced in Section 3.2.2 as a proxy to **market liquidity, understood as the possibility for market participants to conduct transactions at any time and for any period without major price distortion**. However, extended assessment efforts **would require detailed modelling of bidding and hedging processes**, notably in the context of forward markets, as conducted in (Bevin-McCrimmon *et al.*, 2018). In particular, ACER's methodology for evaluating market liquidity in the current Bidding Zone Review process relies heavily on the analysis of hedging and risk premia in forward markets (DNV GL Energy, 2020), even though the spot market volumes and the correlation between spot market prices is also explored.

**Liquidity is therefore rarely addressed in the literature on bidding zones**. Nevertheless, several authors quantify **the impact of zone revision on transaction volumes for thermal and renewable generation units**, which still gives a snapshot of the physical management of the market participants' portfolio (Egerer, Weibezahn and Hermann, 2016; Van Den Bergh *et al.*, 2016). This option will be further explored in Chapter 5 on a 2025-2040 modeling period.

Nonetheless, **market liquidity can also be approached through the stability of price signals**. In particular, several authors and institutions introduce the notion of "market depth" (Bemš *et al.*, 2016; ENTSO-E, 2018b; EFET, 2019), defined as the extent to which a market can absorb transaction volumes without major impact on the price. The monitoring of price variability and robustness therefore appears essential for two main reasons. First, it is instrumental in qualifying market efficiency on a given time horizon. Second, on a system

dynamic perspective, differentiated price signals suggest a divergence of investment trajectories from a zone configuration to another – which will also be explored in Chapter 5.

**Two main price indicators** can therefore be extracted from the literature. On the one hand, **price volatility** can be approached by computing the standard deviation of a series of zonal prices, which Mayer (Mayer and Trück, 2018) deems also relevant for data series with no time correlation. On the other hand, **price vulnerability** can be addressed through computing the average price increase resulting from the loss of the thermal generator of highest capacity of a given zone. This indicator is directly derived from the classical N-1 contingency criterion, notably described in (Singh and Parida, 2013).

In the remainder of this chapter, **we illustrate this multi-dimensional evaluation approach on the previously introduced 30-bus benchmark and pan-European grid models**, featuring short- to long-term system evolution scenarios.

## 4.2 RESULTS FROM THE 30-BUS BENCHMARK SYSTEM

In this section, we provide first evidence from a multidimensional, multi-horizon evaluation of clustering-based zone delineations with our 30-bus benchmark grid model. **We first concentrate on the previously introduced redispatch effort and zone weight indexes** and we introduce **short- to long-term system evolution scenarios** that we design according to reference projections from the European power system.

### 4.2.1 System Evolution Scenarios

The stability and robustness of bidding zones over time is explicitly referenced in the CACM guidelines (European Commission, 2015). The main take of the First Edition of the Bidding Zone Review (ENTSO-E, 2018b) on this topic is that as the number of zones increase, zone borders are associated with grid bottlenecks that are less structural and stable. Authors therefore conclude that **reconfiguration scenarios involving numerous zone splittings may negatively affect zone**

**robustness**, since congestion management benefits may be less permanent.

This analysis was later corroborated by ENTSO-E's Bidding Zone Technical Report for the 2018-2020 period (ENTSO-E, 2021a), noting that *"In the timeframe 'Capacity calculation for the purpose of day-ahead capacity allocation', reported congestions with a relative high frequency are generally at bidding zone borders or in their direct vicinity"*. This suggests that the constitution of new zone borders may **lead to complexify the market design while targeting congestion phenomena of relatively low frequency.**

**The multi-horizon relevance of bidding zone delineations is nonetheless rarely addressed in the literature.** In (Burstedde, 2012), Burstedde considers 2015 and 2020 dispatch scenarios for Central Western Europe and finds out that the optimal number of zones is not the same for both horizons. In (Felling and Weber, 2018), Felling et al. use a set of six scenarios representing distinct system evolution trends regarding grid development, renewable integration, demand and several exogenous economic factors. Hierarchical clustering is then performed on representative LMP series, purportedly creating zone delineations that are robust to any system trajectory.

In an attempt to combine both approaches, **we designed a multi-dimensional, multi-horizon set of evolution scenarios for our 30-bus benchmark system.** We integrated **three main dimensions, namely grid reinforcement, renewable integration and demand,** with medium and long term declinations.

As detailed in Section 3.2.2, we first worked on 1,500 short-term dispatch configurations with 300 wind and PV generation scenarios and five demand scenarios from 40 to 80 gigawatts. In this robustness analysis, the renewable generation scenarios were replaced by 300 scenarios extracted from the "Near Future" database presented in (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016; *Renewables.ninja*, 2022). This alternative database accounts for expected performances for renewable generation technologies on a medium term perspective.

Once again, we used K-Means clustering to consolidate these 300 representative scenarios based on historical data from 1985 to 2016. A comparison of statistical distributions of capacity factors from both scenario sets is presented in Table 4.III.

Table 4.III: Statistical Distribution of Capacity Factors used for the 300 Renewable Generation Scenarios - Short-Term v. Near Future.

<i>Technology – Scenario Set</i>	<i>Q1</i>	<i>Median</i>	<i>Q3</i>
<i>Wind On. – Short-Term</i>	6.3%	13.6%	24.8%
<i>Wind On. – Near Future</i>	9.0%	17.5%	31.5%
<i>Wind Off. – Short-Term</i>	7.8%	24.1%	51.3%
<i>Wind Off. – Near Future</i>	6.9%	22.8%	51.6%
<i>PV</i>	0	0.2%	21.9%

This update of renewable capacity factor scenario was used to represent the **medium term evolution of our 30-bus benchmark system regarding renewable integration**. In the **long-term declination for renewable integration**, we introduced a **structural change of the generation fleet**, cutting thermal capacities by half while setting a 50% increase of renewable capacities.

On the demand side, we designed a **high and a low demand scenario that we declined over our two horizons**. In the **medium run**, we introduced a **5 gigawatts up and down variation** of general demand levels, which resulted in a 45-85 GW and a 35-75 GW demand scenario – which corresponds to a  $\pm 8\%$  demand variation from the average level. While European electricity demand is expected to increase in the next decades, this up-or-down medium-term demand variation is mostly illustrative of the yearly variability of electricity consumption. On the other hand, we chose to illustrate **two trends regarding electrification of uses** for long-term demand scenarios. The high demand scenario therefore consists in a 20% raise of demand levels,

which is scaled from ENTSO-E's 2040 Global Ambition scenario (ENTSO-E, 2020d), resulting in a 48 to 96 GW demand range.

On the other hand, the low demand version consists in a status quo 40 to 80 gigawatts demand range, which illustrates a lack of progression in the said electrification. In particular, the 20% increase was distributed in proportion to the installed RES capacity of each Status Quo bidding zone. This creates a new distribution of demand that is reflective of the proactivity of each area regarding decarbonation objectives. Details are available in Appendix A.

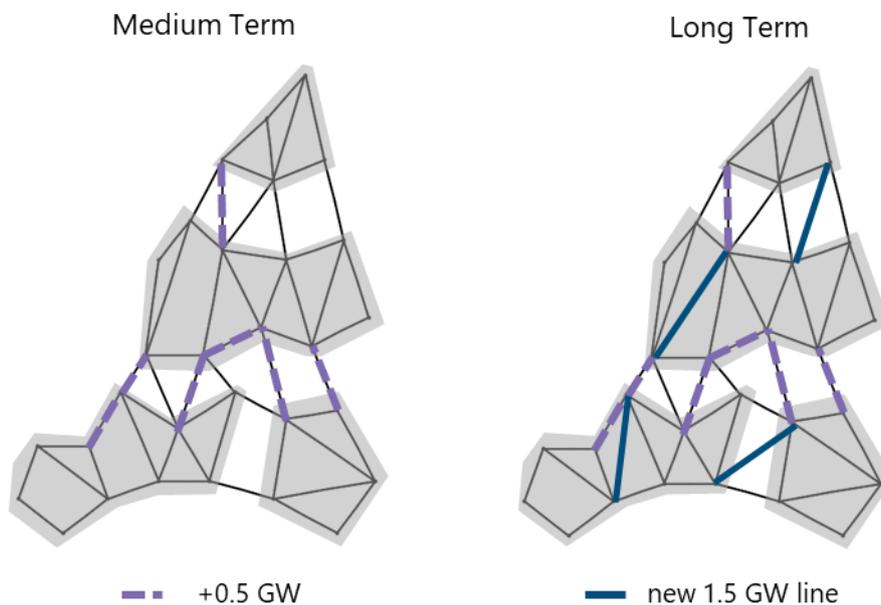


Figure 4.1: Grid Reinforcements in the Medium and Long Term Scenarios.

**Grid reinforcements were also introduced gradually between a medium term and a long term scenario.** In the first step, only **line reinforcements** are conducted. We targeted and reinforced network elements with a high risk of presenting a load superior to 85%, measuring a 5% value at risk over all short-term dispatch scenarios. These lines therefore went from a 1.5 to a 2 gigawatts capacity. In the long run evolution scenario, we **combined line reinforcements to the addition of four 400kV lines** with a capacity of 1.5 gigawatt in the areas where congestions were observed in the short run. This approach **illustrates how TSOs give priority to congested areas for grid investments**, notably in line with congestion rents. Figure 4.1 shows the location of said grid reinforcements.

While these system variations do not correspond to a strictly realistic approach, they are nonetheless **illustrative of how grid reinforcements are generally targeted towards most congested axes of the European power system.** In that sense, they allow the benchmark of the general methods and parameters later featured on our large-scale case study.

We later studied several combinations of these evolution options for renewable integration, grid development and demand. This resulted in four system evolution scenarios in the medium run, and four in the long run. The genealogy of the eight system evolution scenarios is presented in Figure 4.2, and quantitative details in Appendix A.

We therefore obtained a set of evolution scenarios that combine distinct system trajectories upon two distinct horizons for our 30-Bus Benchmark System.

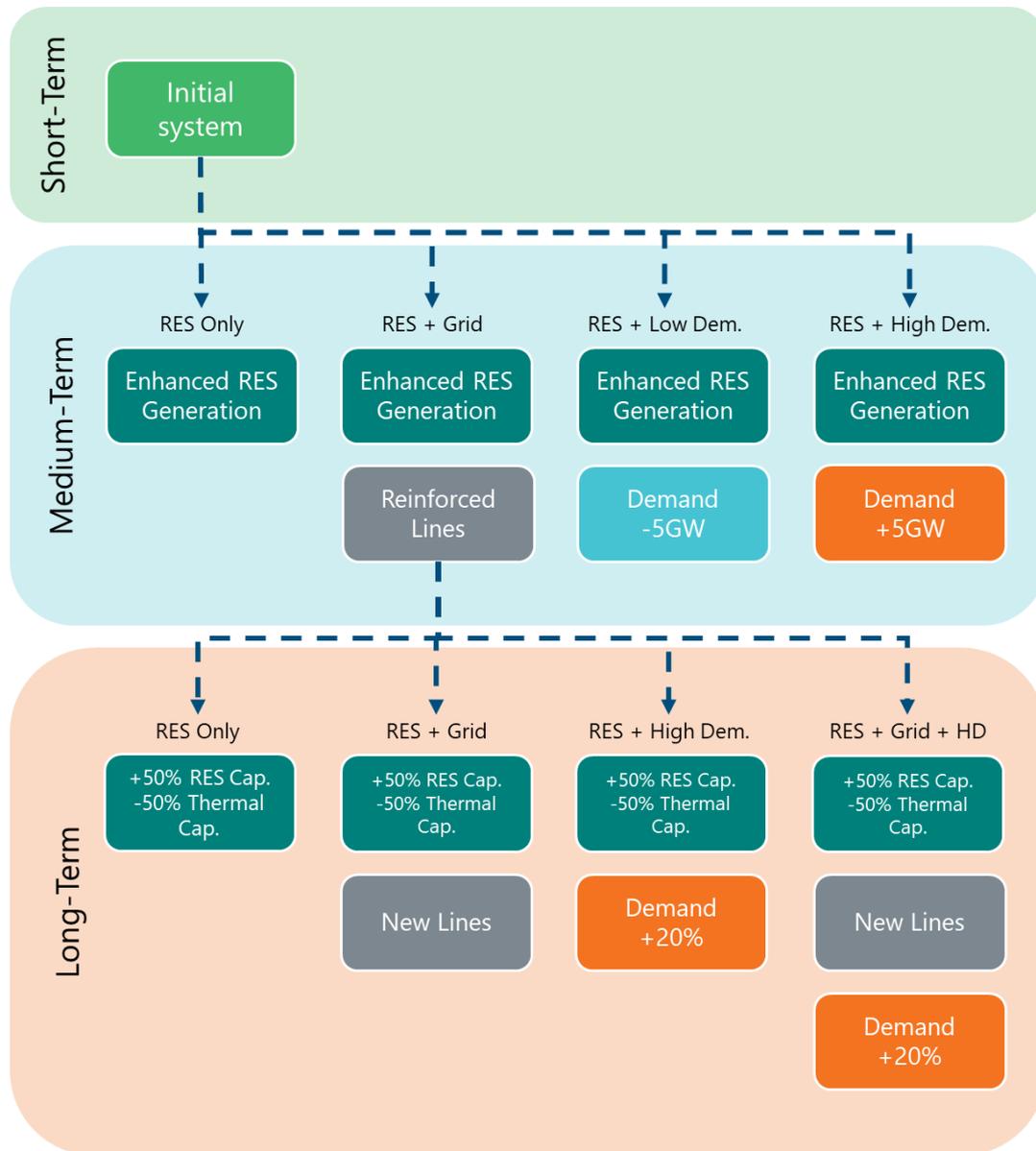


Figure 4.2: Medium- and Long-Term Scenario Genealogy.

## 4.2.2 Multi-Horizon Analysis

In the context of this benchmark step, we first conducted an evaluation of clustering-based zone delineations using only the redispatch effort (RE) and zone weight ( $W_z$ ) indicators introduced in Section 3.2.2. Series of 1,500 scenarized optimal power flow simulations were conducted upon the eight system evolution scenarios. **We then applied K-Means clustering to the resulting LMP series to generate candidate zone delineations**, in accordance with our finding in Section 3.3.2 that K-Means was more performant than Hierarchical clustering on this specific grid model.

As in Section 3.2.2, we then **generated grid partitions for every possible input zone number from 2 to 25, over the eight evolution scenarios**. We calculated RE and  $W_z$  indicators for each, which resulted in 192 evaluations. In line with the work presented in (Burstedde, 2012), **we first addressed the influence of system evolution scenarios on the desirable number of zones**. In Section 3.2.2, we had determined that a six-zone configuration was a good candidate in the short run, since it allowed the strongest reduction of redispatch efforts without diminishing the smallest zone weight. The same rationale was applied to our eight system evolution scenarios, with results presented in Figure 4.3.

This overview provides a first insight on the robustness of clustering-based zone delineations: even though configurations with more zones may appear optimal in the short-run, **structural system evolutions are likely to blur the congestion map, leading to prefer configurations with less zones**. Even rather continuous mid- to long-term system evolutions like "RES +Grid → RES Only" or "RES + Grid → RES + Grid" return clearly diverging optimal zone configurations.

These "optimal" zone numbers were nonetheless obtained using an equal weighting of redispatch effort and zone weight, which may seem rather arbitrary. In particular, the zone weight indicator should be interpreted less like a specific market efficiency criteria, and more like **an indicator of how fundamentally market dynamics could be impacted by bidding zone revision**. The preservation of zone weight values is therefore not an objective as such, yet **a good indicator of**

**the point where redispatching considerations start to get in the way of market efficiency.**

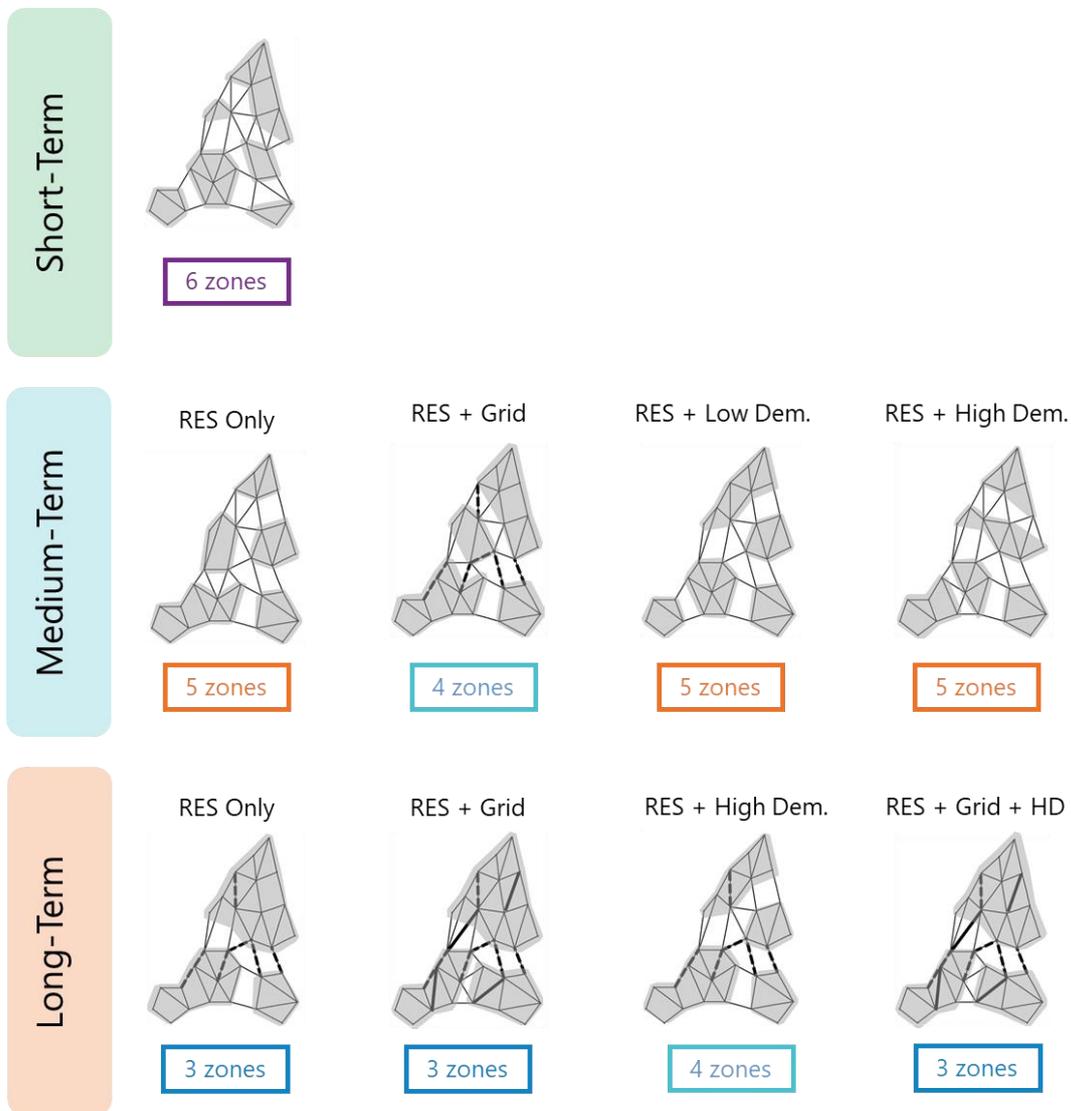


Figure 4.3: "Optimal" Zonal Configuration per System Evolution Scenario.

We therefore complemented this approach with a statistical analysis of the 192 pairs of indicators obtained from evaluating zone delineations. This was meant to **illustrate what decision-making could look like** when it comes to a trade-off between redispatching gains and the preservation of zone weights.

In Figure 4.4, we represented box plots for both indicators, from a

medium to a long term perspective, **highlighting two reconfiguration options: implementing less or more than five zones.** As a reference, we evaluated the RE and  $W_z$  performance of the status quo configuration with four zones, that we introduced in Section 2.2. This status quo performance was respectively averaged over all medium- and all long-term dispatch scenarios. In coherence with RE and  $W_z$  values presented in Section 3.2, RE values are more sensitive to higher input number of zones, which translates into wider boxplots, and the opposite is observed for zone weight

**On a medium-term perspective, configurations with six zones or more still seem to offer opportunities for significantly reducing redispatching with limited decrease of the minimum zone weight.** The choice of a configuration with five zones or less therefore seems quite conservative regarding zone weights, especially considering this does not allow a strong decrease of redispatching efforts. Moreover, all four system trajectories (“RES Only”, “RES + Grid”, “RES + Low Demand” and “RES + High Demand”) return rather similar performances. We also note that the RE performance data on the “> 5 zones” side is quite scattered, which tends to show that **configurations with more than five zones represent an efficient lever regarding congestion management.**

On the long-term picture, **implementing any configuration with six zones or more would mean cutting at least 60% of the weight of the smallest market.** Nonetheless, configurations with five zones or less are quite unsatisfactory regarding redispatch levels, since only the “RES + High Demand” and the “RES + Grid + High Demand” scenarios allow a reduction of redispatch efforts. From a more general perspective, we observe that RE performance data is less scattered than in previous findings. **This suggests that bidding zone revision gradually becomes less efficient over time regarding congestion management benefits.**

### Medium Term



### Long Term

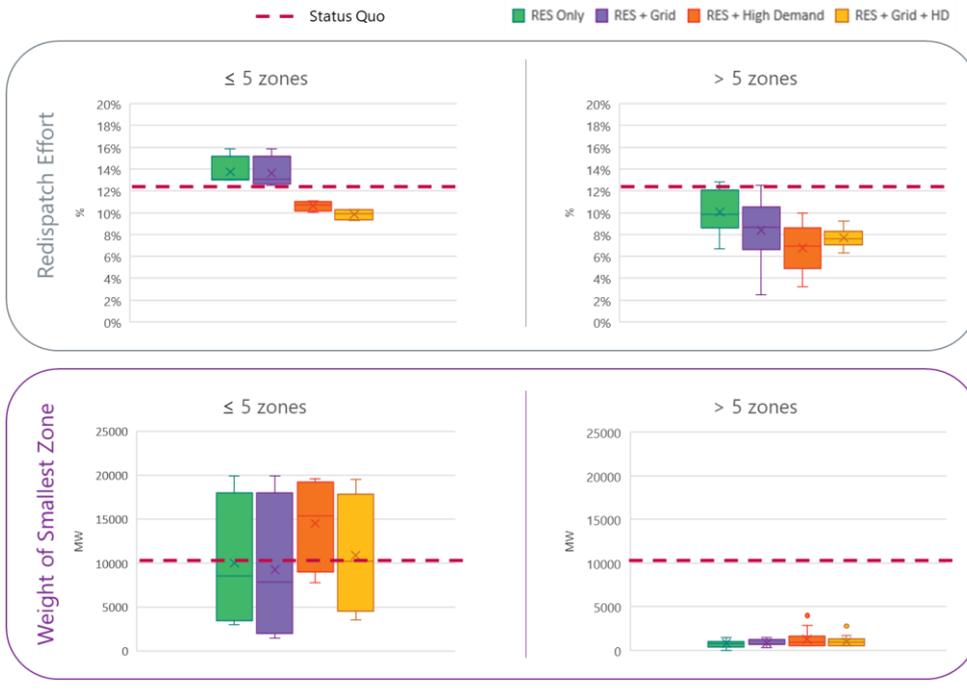


Figure 4.4: Evaluation of Clustering-Based Delineations for the 30-Bus System.

This preliminary analysis may seem counter-intuitive since it is not based on a single zone reconfiguration in the short run, yet on a multitude of possible zone delineation candidates in the medium- and long-run. We nonetheless identify two main findings through this approach.

First, we illustrated a trade-off mechanism between the system operation and market efficiency dimensions, and the fact that such trade-offs may be accentuated in the future by structural system evolutions. **Even if, in the short run, there is a prevailing idea that an increase in the number of zones would be relevant for congestion management despite liquidity concerns, the adoption of such configurations would create structural impacts on market dynamics and could expose the system to amplifying liquidity losses in the long run.**

**Second, this analysis tends to show that the relevance of a bidding zone revision is highly dependent on the coordinated evolution of the generation fleet, electricity demand and grid infrastructure.** In the long-term picture, a possible compromise seems to come from the "RES + Grid + High Demand" trajectory with less than five zones, since significant redispatching gains are observed with limited reduction of the minimal zone weight. As this trajectory corresponds to a significant development of renewable sources combined with major grid reinforcements and electrification of uses, **this suggests that the efficiency of bidding zone revision is most robust when associated with judicious anticipation of long-term system evolution trajectories.**

In this analysis, we did not use the full spectrum of indicators presented in Section 1 due to the overall simplicity of the model considered, leaving less uncertainty on our robustness diagnosis. A more extensive approach will be presented in the realistic large-scale case study of the next section.



## 4.3 EXTRAPOLATION TO BIDDING ZONES OF THE EUROPEAN POWER SYSTEM

Our contribution in the first sections of this chapter has been three-fold. First, we **identified complementary indicator to address both operational and market dynamics** through conventional modeling frameworks and on a pan-European level. Second, we have built first evidence of **fundamental trade-off mechanisms between congestion management and market efficiency** in the context of a bidding zone revision. Finally, we illustrated **robustness concerns** regarding the medium- to long-term relevance of zone configurations that are optimized for the short run.

Nonetheless, expanding this evaluation to the pan-European system requires additional efforts regarding **the overall realism and consistency of examined scenarios**. In this section, we describe our methodology for assessing the performance of clustering-based zone delineations using short- to long-term static dispatch scenarios.

### 4.3.1 Evaluation Methodology

As in Section 4.2, this analysis was conducted based on **series of independent optimal power flow simulations** from which we deduced zonal dispatches, under the assumptions detailed in Section 2.1. We therefore **prioritized the detailed consideration of grid constraints** over dynamic unit commitment optimization, in a very similar way as presented in (Marinho *et al.*, 2017b; Felling and Weber, 2018).

Our short-term evaluation was conducted on the **600 dispatch scenarios** that were introduced in Section 3.3.1, based on summer and winter load levels from ENTSO-E’s TYNDP (ENTSO-E, 2020d) and two batches of 300 representative renewable capacity factors from (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016; *Renewables.ninja*, 2022). We therefore designed similar sets of 600 dispatch scenarios for the 2030 and 2040 horizons, using **updated generation fleets, grid reinforcements and demand levels from the scenario “National Trends” of ENTSO-E’s TYNDP 2020**. Figure 4.5 introduces the installed generation capacities after adaptation to our static grid model with twelve main bidding zones from Continental Europe and eleven simplified peripheric areas.

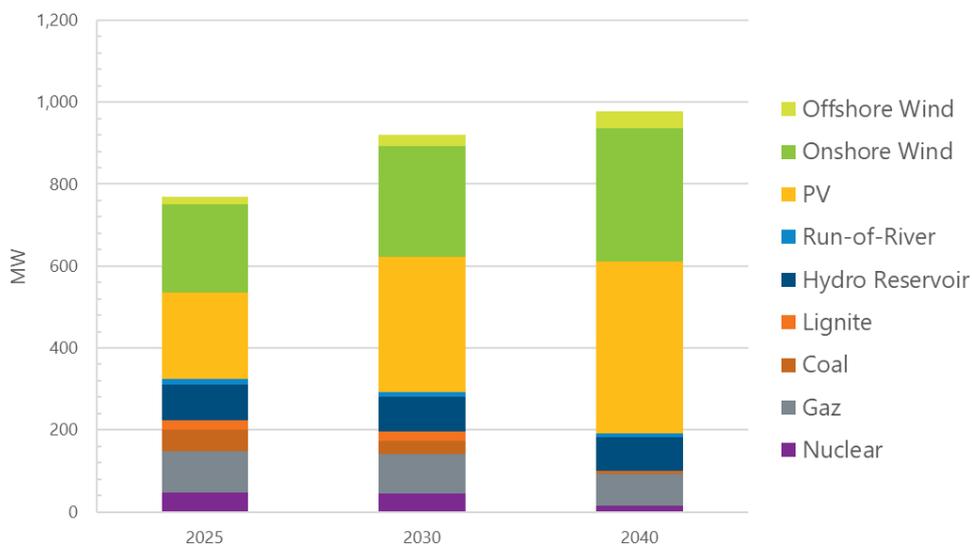


Figure 4.5: Evolution of Installed Capacities - Pan-European Grid Model.

Series of 600 DC-OPF simulations were therefore conducted using Digsilent’s PowerFactory (DigSilent GmbH, 2020) and an Intel Core 2.70 GHz processor, with a similar process as described in Section 3.3.1. We therefore obtained three sets of six hundred realistic, consistent and extensive dispatch results. These therefore served as a **base of our multi-horizon and multi-dimensional evaluation of the candidate zone delineations** presented in Section 3.3.2.

In line with the review conducted in Section 4.1, we have been able to propose an extensive evaluation grid. As stated in the beginning of this chapter, our objective here is to **quantify system-wide impacts of a bidding zone revision** on key techno-economic aspects. Some of the previously introduced indicators are already compliant with this objective, and were simply averaged over the relevant batch of 600 equally representative dispatch scenarios.

Other indicators like **standard price deviation or price vulnerability are nonetheless zone-specific**. They were consequently **computed for each zone, then averaged over all zones** with an equal weighting in order to not favor specific areas over others. In particular, standard price deviation was computed for each zone over all representative dispatch scenarios, then averaged over all zones. On the other hand, we obtained the average price vulnerability by successively computing price variations resulting from the loss of the thermal generator of highest capacity in each zone. This indicator was then averaged over all zones and dispatch scenarios.

In order to account for **the occurrence of extreme price events in the system**, we also computed **10% values at risk (VaR)** for both standard price deviation and price vulnerability values. These values at risk are therefore representative of the highest values of zonal price volatility and of extreme price vulnerability events over all zones and dispatch scenarios.

As detailed with the use of the *Wz* indicator in the previous section, these indicators on price formation insofar as **they describe the extent to which status quo market dynamics can be disrupted by a new zone configuration**. Significant impacts on price signals are in fact likely to affect investment dynamic. While the work presented in Chapters 4 and 5 do not feature a specific analysis of risk management, further impacts on the market penetration of different energy sources and investment trajectories will be discussed in Chapter 5.

Table 4.IV: Evaluation Grid - Pan-European Grid Model.

System Operation	Economic Transfers	Price Formation
<b>Redispatch Effort (RE)</b> – Averaged over all dispatch scenarios.	<b>Net Congestion Rent (<math>\overline{Y_{TSO}}</math>)</b> – Averaged over all dispatch scenarios.	<b>Standard Price Deviation</b> – Averaged over all zones.
	<b>Producer Margin (<math>\Pi_{prod}</math>)</b> – Averaged over all dispatch scenarios.	<b>Standard Price Deviation</b> – 10% Value at Risk over all zones.
	<b>Consumption Cost (<math>C_{cons}</math>)</b> – Averaged over all dispatch scenarios.	<b>Price Vulnerability</b> – Averaged over all zones and dispatch scenarios.
		<b>Price Vulnerability</b> – 10% Value at Risk averaged over all zones and dispatch scenarios.

### 4.3.2 Multi-Horizon Analysis

The results from our multi-dimensional robustness analysis are presented in this section. Most indicators are presented in the form of percentages, either as relative variations from status quo levels or as normalized indicators. Due to the number of considered scenario, any variation of 2% or more of any of these indicators is deemed significant. **The nine candidate zone delineations presented in Section 3.3.2 were evaluated, as well as the status quo zone configuration.** As a reminder, these zone revision scenarios are distinguished by:

- The use of three main clustering approaches, namely weighted K-Means (wK), weighted Hierarchical (wH) and connected, weighted Hierarchical clustering (c-wH) ;
- Their representativity of three zone revision trends : “Zone Shuffle” (ZS), “Big Country Split” (BCS) and “Regionalized System” (RS).

**Results are then presented over the three studied horizons: 2025, 2030 and 2040.**

Evidences from the redispatch effort index are featured in Figure 4.6, presenting both average status quo RE levels and reductions observed depending on the zone revision scenario. As of 2025, it is observed

that redispatching levels decrease with the number of zones, up to 6% from the average 14.8% RE level for 2025. This result is a consequence of using LMP-based clustering to design candidate zone delineations under 2025 dispatch scenarios, and meets the observations of previous similar modeling efforts (Breuer and Moser, 2014; Marinho *et al.*, 2017b).

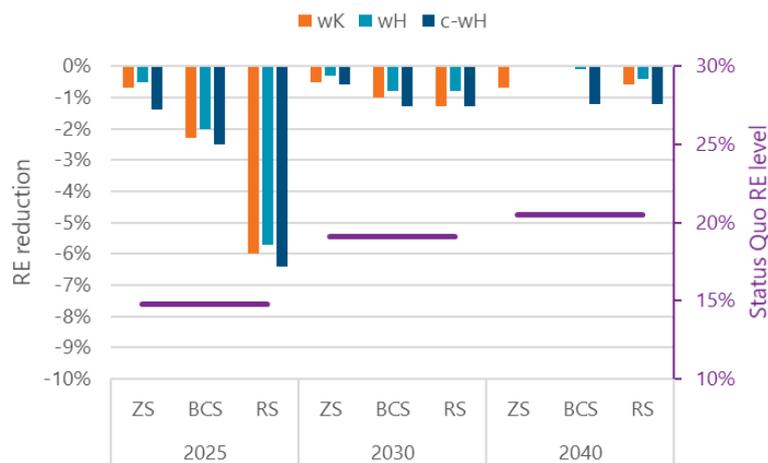


Figure 4.6: RE Reduction and Status Quo Levels - Pan-European Grid

Nonetheless, the considered zone reconfigurations **prove significantly less performant whenever confronted to 2030 and 2040 dispatch scenarios**: while status quo RE levels sore to 19.1% and 20.5% respectively, the considered zone revisions do not allow significant reductions of redispatch efforts. **This keeps overall RE levels significantly higher than the 2025 status quo redispatch effort.** Zone delinations that may appear optimal in the short-run may therefore prove way less performant in the medium and long run.

From the perspective of system costs and revenues, the saved redispatch effort tend to improve net congestion revenues for transmission system operators. As illustrated in Equation (4.7), this increase is reported on both the producer margin and the cost of consumption. In fact, it has been clarified in Section 4.1 that **the quantity  $C_{cons} - \overline{Y}_{TSO} - \Pi_{prod}$  is invariant for all zone configurations.**



Figure 4.7: Structural Economic Transfers in Comparison to Status Quo Levels - Pan-European Grid Model.

Figure 4.7 presents how our selection of zone revision scenarios impacts the three dimensions presented in Section 4.1.2: , consumption cost  $C_{cons}$ , net congestion rent  $\overline{Y}_{TSO}$  and producer margin  $\Pi_{prod}$ . In particular, the variation of all three indicators are presented as percentages of the Status Quo consumption costs. It therefore becomes visible that **the increase of  $C_{cons}$  is the sum of both variations of  $\overline{Y}_{TSO}$  and  $\Pi_{prod}$ .**

A clear dynamic can be identified on the 2025 scope. For all clustering methods, configurations involving more zones – i.e. the “Big Country Split” and the “Regionalized System” delineations – imply a clear shift of system costs and revenues, with an increase approaching 5% o case of System Regionalization.

We therefore see a clear trade-off mechanism between the reduction of redispatch effort and a tendency to redirect a bigger share of system costs onto consumers. In particular, Figure 4.7 shows that **TSOs only capture a minor part of the consumption cost increase**, which shows that **the pressure on consumers is much more amplified than the signals actually calling for grid reinforcements.**

Nonetheless, **the 2025 horizon still seems to offer potential for reconciling operational benefits while keeping a limited level of structural economic transfers.** In particular, “Big Country Split” configurations obtained with the (wK) and (c-wH) allow a significant reduction of the RE indicator (i.e. superior to 2%) while keeping economic transfers under a 3% threshold.

**On a medium- to long-term perspective, structural economic transfers become much more disproportionate in comparison to operational benefits.** We previously showed that clustering-based zone configurations that were obtained upon 2025 dispatch scenarios are less relevant to the 2030 and 2040 congestion maps, hence do not result in significant RE reduction. Nonetheless, even for these horizons, zone revisions induce distributions of system costs and revenues that significantly differ from the status quo.

The shift in our three cost and revenue indicators progresses between 2030 and 2040, yet not as much as between 2025 and 2030. Still, both

“Big Country Split” and “Regionalized System” revisions tend to return 5% to 9% increases in consumption costs, with only 20 to 25% of this being captured by congestion rents. While “Big Country Split” results seemed to remain in alignment with “Zone Shuffle” outcomes over the 2025 horizon, **both “Big Country Split” and “Regionalized System” sets of scenarios therefore tend to accentuate structural economic transfers in the medium to long run.**

Two main behaviours therefore emerge. On the one hand, the three “Zone Shuffle” configurations offer **limited overall reduction of redispatching in the short to long run, yet they preserve the balance of system costs and revenue between producers, TSOs and consumers.** On the other hand, “Big Country Split” and “Regionalized System” configurations allow **significant yet non-robust short-term reduction of redispatch efforts, but they tend to transfer significant shares of system costs onto consumers upon 2030 and 2040 dispatch scenarios,** with limited transfer in congestion revenues for TSOs.

This distinction can also be observed regarding price formation. Figure 4.8 presents average and 10% Value at Risk records for standard price deviation and price vulnerabilities, in comparison to status quo values.

In the 2025 perspective, only “Regionalized System” configurations stand out with significantly higher 10%VaR values for the price vulnerability indicator – yet average price vulnerability remains less than 2% higher than status quo levels. Although the 2030 results do not highlight significant differentials, 2040 projections show that “Big Country Split” and “Regionalized System” configurations induce similar and neatly higher levels of price volatility and vulnerability.

In particular, **this increase of the price vulnerability indicator tends to illustrate that configurations with more zones may increase price sensitivity to the influence of strategic thermal generation units** – and therefore more exposed to the exercise of market power, while also potentially affecting risk management.

On a more general view, even though the connected, weighted Hierarchical (c-wH) method seems more efficient regarding RE

reduction, no clustering method clearly stands out from the others on all indicators, especially in the medium and long run. While the improvement of clustering methods can be helpful for more accurate consideration of grid bottlenecks, **the very principle of congestion-based zone revision seems to inevitably lead to this type of trade-offs between RE reduction, economic transfers and price formation.**

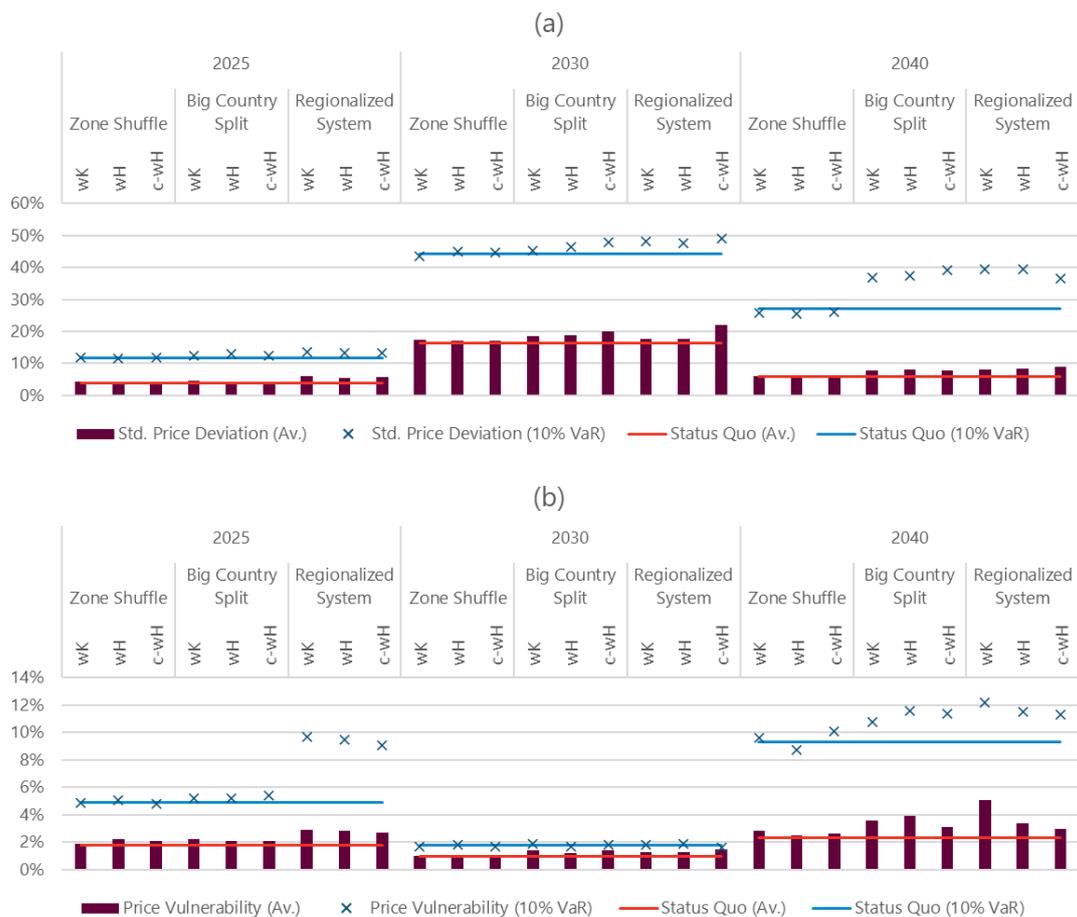


Figure 4.8: Price Volatility (a) and Vulnerability (b) in Comparison to Status Quo Levels - Pan-European Grid Model



## KEY FINDINGS – CHAPTER 4

In this chapter, we presented our methodology for assessing clustering-based candidate zone configurations. Based on the literature and the diagnoses of previous chapters, **we constituted an extensive evaluation grid that corresponds to our ambition for a multi-dimensional and multi horizon analysis.** While the next chapter will strengthen our analysis of medium- to long-term dynamics, we identified key trade-off mechanisms and robustness issues using our 30-bus benchmark system and our large-scale European static grid model.

The use of our 30-bus benchmark system allowed us to validate general trends regarding system operation, market dynamics and their overall robustness to system evolution. Using the two benchmark indicators presented in the previous chapter, we notably showed that **zone configurations that seem optimal in the short run may be very different from zone revisions that would be relevant in the future.**

Our final contribution over our European grid model is two-fold. On the one hand, we show that **in the short run, bidding zone revision can bring significant benefits in terms of redispatching needs.** However, it appears that **configurations with more zones cause a systematic increase in consumption costs that corresponds to an increase of producer margins and, on a more limited extent, net congestion rents.** This economic pressure on consumers is therefore quite disproportionate to actual grid investment signals for transmission system operators.

Under these short-term conditions, judicious amendments of the zone configuration nonetheless seem to allow **compromises for improved congestion management with limited disruptions of market dynamics** – even though our analysis does not include transition costs.

On the other hand, we provide evidence that **in the medium to long run, zone delineations allowing significant redispatch effort reduction almost always require careful monitoring of adverse**

**effects on price formation and economic transfers.** In that sense, this quantitative robustness analysis specifically illustrates **robustness concerns in the context of an increased number of zones.** This case study therefore confirms the anticipations of ENTSO-E's First Edition of the Bidding Zone Review (ENTSO-E, 2018b) regarding a loss of robustness. We also contribute to emphasize the **need for a robust market design that encompasses multiple time horizons** in a context where carbon-free generation investments are to be encouraged.

In particular, the pursuit of zonal delineations that secure robust benefits over time may lead future contributions to either integrate several time horizons within the clustering process or examine the possibility of recurring zone revisions. The former solution takes us back to questioning the **sensitivity of model-based delineations to input data, chosen algorithms and parameters**, while the latter raises the issue of **grid and generation investment planning under uncertain market design.**

An essential extension of this work is therefore **to investigate the impact of bidding zone revision on a more dynamic perspective**, integrating generation investments, and sensitivity to grid development. This dimension will be addressed in Chapter 5 through the **combination of Capacity Expansion Planning and Unit Commitment modelling frameworks**, where we notably dive further into market dynamics regarding the use of interconnections and the penetration of competing generation technologies.

## 5 APPLICATION TO LONG-TERM SYSTEM TRAJECTORIES

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In the previous chapter, we presented **a first multi-horizon and multi-dimensional analysis of a series of zone reconfiguration patterns**. This approach was nonetheless limited to batches of 600 non-consecutive demand and renewable generation scenarios, and relied on **a posteriori estimation of zonal dispatches**.

The simulation chain developed in Chapters 2 to 4 nonetheless appeared as a straightforward means to apprehend **general trade-offs between congestion management, price formation and system cost and revenue distribution on a short- to long-term basis**.

In this chapter, we present and **extended simulation chain that bring the focus on market dynamics and generation investment signals**. We perform a first assessment with similar techno-economic indicators as presented in Chapter 4, yet we also concentrate on the impact of bidding zone revision on the market penetration of thermal and renewable sources. This is complemented by a **sensitivity analysis that integrates both generation investments and variations of cross-zonal capacities** in order to address the coordination of grid and generation deployment in the medium to long run.

We therefore construct a pan-European picture regarding the relation of bidding zone reconfiguration to long-term system trajectories, which both expands the reach of our general approach and consolidates previously established results.

Section 5.1 presents our amendments to our first simulation chain and the construction of this new case study. Section 5.2 then presents market dynamics obtained on a 2025 to 2040 simulation period in line with the "National Trends" scenario of ENTSO-E's 2020 edition of the Ten-Year Network Development Plan (ENTSO-E, 2020d). Section 5.3 finally introduces our sensitivity analysis integrating both generation investment trajectories and variations of cross-zonal capacities. Finally, the main highlights of this analyses are summarized in a Table in Section 5.4.



## 5.1 INTRODUCTION OF A COMPLEMENTARY SIMULATION CHAIN

In this section, we introduce **a simulation chain that combines unit commitment and generation expansion planning frameworks**. We also get back on the fundamentals of spatial and temporal price allocation models in the context of a multi-zonal competitive spot electricity market.

We then present the **adaptation of our previous pan-European case study**, which mostly relied on optimal power flow simulations, with the notable addition of Pan-European time series for demand, renewable generation and hydro availability. Our assumptions regarding investment decisions and cross-zonal capacities for several time horizons are also presented.

### 5.1.1 Combining Capacity Expansion Planning and Unit Commitment.

In Section 2.1, we introduced the general notion of economic dispatch and more specifically the formalism for optimal power flow with direct current approximation (DC-OPF). More details on this formalism are available in Franck et al. (Frank, Steponavice and Rebennack, 2012).

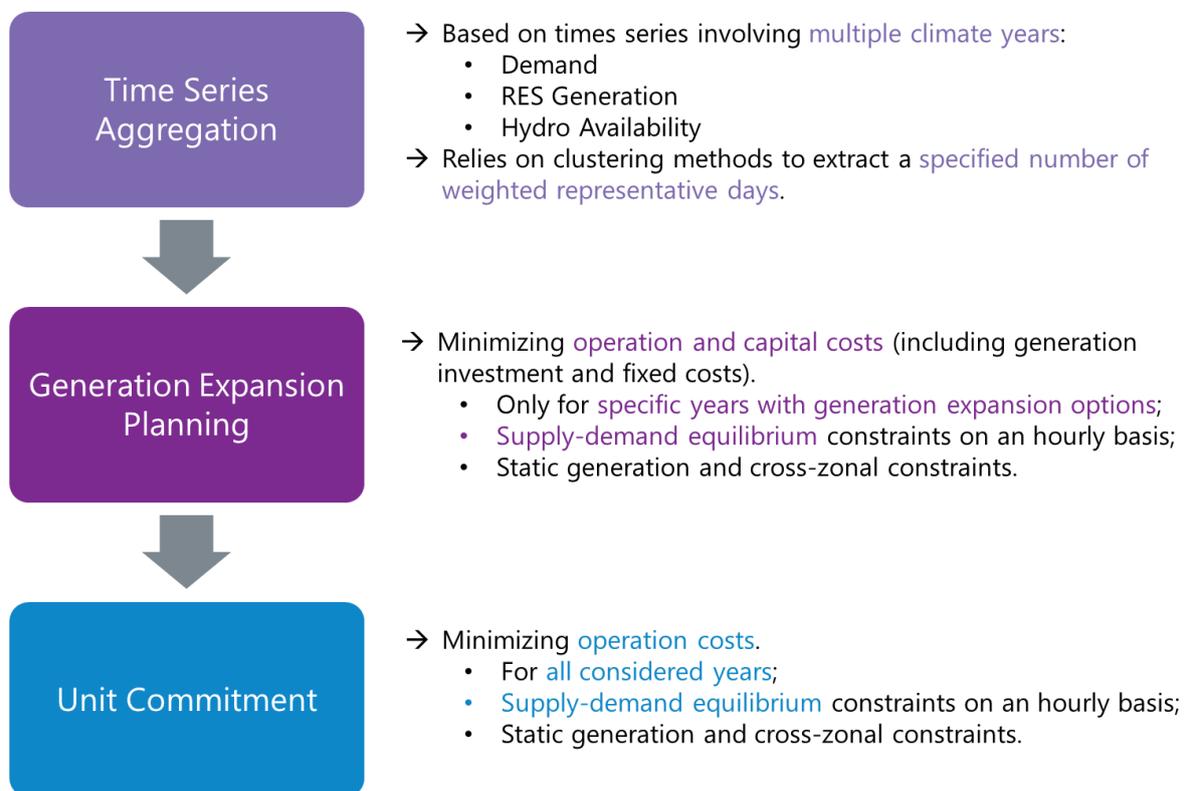
This new simulation process is structured around **three main modules: time series aggregation, generation expansion planning and unit commitment**.

The **time series aggregation** step corresponds to an automated selection of representative days based on extensive input time series that may correspond to several climate years. This step is managed through K-Means clustering that is jointly applied to times series of all types (renewable generation, demand...) in order to secure coherent representation of dispatch conditions. This results in **a set of weighted representative days** which corresponds to cluster centroids. A detailed review on time series aggregation is presented in (Hoffmann *et al.*, 2020)

General equations regarding **generation expansion planning** are presented with more details below. In particular, this step involves an **optimization of operational costs and annualized investment costs**. The corresponding optimization problem is solved over

specified years of the considered time period, on a daily basis and under supply-demand equilibrium constraints. As a complement, a **unit commitment problem** is solved on a hourly basis for all considered years period and under supply-demand equilibrium constraints.

The main outputs from this simulation process is two-fold. On the one hand, yearly system trajectories including generation capacities and investment costs are provided for relevant years. On the other hand, the final unit commitment step results in hourly time series featuring price and generation data for all modelled years. The overall simulation process is summarized in Figure 5.1.



*Figure 5.1: A Summary of the Additional Simulation Chain.*

From a more theoretical point of view, this simulation chain derives from the **traditional framework of the Spatial Price Equilibrium problem**, which was first formalized by Paul A. Samuelson in the 1950s (American and Review, 1952). The main contribution of Samuelson was

to propose a formulation that addresses the Cournot-Enke problem, which corresponds to a competitive equilibrium between separate yet interconnected markets, within the standard linear programming framework of the Koopman-Hitchcock minimum-transport-cost problem.

This breakthrough was consolidated in the ensuing years and decades, notably addressing the interaction of different types of competition between the interconnected markets, from the presence of monopolies (Takayama and Judge, 1964; Harker, 1986) to the overall compatibility with the Cournot – i.e. quantity-based – competitive framework (Yang, Hwang and Sohng, 2002). As detailed in (Ventosa *et al.*, 2005), Cournot equilibrium has then become the preeminent framework regarding market optimization. This simply means that these optimization approaches will involve market participants that seek to maximize the sold quantity rather than establish strategic behaviors upon the supply function of their competitors.

In this work, **we have been relying on previously developed modules for Time Series Aggregation, Generation Expansion Planning and Unit Commitment**, benefitting from Python scripts that are also presented in the work of Lebeau *et al.* (Lebeau *et al.*, 2021). A representation of the overall simulation chain featured in Chapters 2 to 5 and highlighting our main contributions will be presented in Section 5.1.2. In particular, we will also detail our network reduction efforts in that section.

A more general perspective on the Generation Expansion Planning framework is also provided in (Kagiannas, Askounis and Psarras, 2004). While the optimization problem solved in the following case study relies on traditional joint minimization of capital and operational system costs, Kagiannas *et al.* also explore more computationally challenging frameworks that involve strategic interactions between market participants.

Let us nonetheless introduce the main equations regarding the Generation Expansion Planning module. Due to tractability concerns, **only static constraints – i.e. that do not impact consecutive time steps – were taken into account**. Pumped hydro storage facilities

were therefore aggregated to dispatchable hydro capacities, with daily charge scenarios being reported on the total available reservoir inflow. Additional equations including storage behaviours can nonetheless be found in (Lebeau *et al.*, 2021).

### **Objective Function**

$$\min \sum_{y \in Y^*} \left( \sum_{g \in G} \text{om} c_{g,y} \cdot \bar{P}_{g,y,h} + \sum_{g \in G^{\text{inv}}} i c_g \cdot \bar{P}_y^{\text{new}} + \sum_{h \in H} \left( \sum_{g \in G^{\text{disp}}} c_{g,y} P_{g,y,h} + \sum_{z \in \text{BZ}} \text{VoLL} \cdot \text{ENS}_{z,y,h} \right) \right) \quad (5.1)$$

### **Constraints**

Zonal supply demand equilibrium:

$$\sum_{g \in G} \delta_{g,z} P_{g,y,h} + \text{ENS}_{z,y,h} = D_{z,y,h} + \text{NE} x_{z,y,h}; \quad \forall z \in \text{BZ}; \quad \forall y \in Y^*; \quad \forall h \in H \quad (5.2)$$

Generator Capacity:

$$P_g \leq \bar{P}_{g,y,h}, \quad \forall g \in G^{\text{disp}}; \quad \forall y \in Y^*; \quad \forall h \in H \quad (5.3)$$

RES Generation:

$$P_{g,y,h} + P_{g,y,h}^{\text{curt}} = \text{cap}_{g,y,h} \cdot \bar{P}_{g,y,h}; \quad \forall g \in G \setminus G^{\text{disp}}; \quad \forall y \in Y^*; \quad \forall h \in H \quad (5.4)$$

Cross-Zonal Exchanges:

$$\text{NE} x_{z,y,h} = \sum_{z' \in \text{BZ}^2} \sigma_{z,z'} \cdot f_{z \rightarrow z',y,h}, \quad \forall z \in \text{BZ}; \quad \forall y \in Y^*; \quad \forall h \in H \quad (5.5)$$

$$-\bar{f}_{z' \rightarrow z,y} \leq f_{z \rightarrow z',y,h} \leq \bar{f}_{z \rightarrow z',y}; \quad \forall (z, z') \in \text{BZ}^2; \quad \forall y \in Y^*; \quad \forall h \in H \quad (5.6)$$

Investment dynamic :

$$\bar{P}_y^{\text{new}} \geq \tau_{y' \leq y} \cdot \bar{P}_{y'}^{\text{new}}; \quad \forall (y, y') \in Y^{*2} \quad (5.7)$$

### **Sets**

$Y^*$	Set of years with generation expansion options
$H$	Set of hours in the year

BZ	Set of bidding zones
G	Set of generators
$G^{\text{disp}}$	Set of dispatchable generators
$G^{\text{inv}}$	Set of generators with investment options.
$G^z$	Set of generators in bidding zone z.

### Variables

$P_{g,y,h}$	Output of generator g at hour h of year y
$f_{z \rightarrow z',y,h}$	Oriented flow between z and z' at hour h in year y
$NEx_{z,y,h}$	Net position of zone z at hour h of year y
$ENS_{z,y,h}$	Energy not served in zone z at hour h of year y
$P_{g,y,h}^{\text{curt}}$	Curtailment from fatal generator g at at hour h of year y
$\bar{P}_y^{\text{new}}$	Cumulated new capacity for generator g in year y

### Parameters

$D_{z,y,h}$	Demand in zone z at hour h of year y
$\bar{P}_{g,y,h}$	Capacity of generator g at hour h of year y
$\bar{f}_{z \rightarrow z',y}$	Exchange capacity from zone z to zone z' in year y
$\text{cap}_{g,y,h}$	Capacity factor of fatal generator g at hour h in year y
$\text{omc}_{g,y}$	Nominal annualized fixed cost for operation and maintenance of generator g in year y
$\text{ic}_{g,y,h}$	Nominal annualized cost for investment in capacity for generator g in year y
$c_{g,y}$	Nominal operating cost of generator g in year y
VoLL	Value of Loss of Load
$\delta_{g,z}$	Equals 1 if generator g is in zone z, 0 if not
$\sigma_{z,z'}$	Equals 1 if zones z and z' are interconnected, 0 if not
$\tau_{y' \leq y}$	Equals 1 if year y' is prior to year y, 0 if not

The overall formulation of this optimization problem is therefore **solvable within a linear framework**, which allows ambitious modelling approaches from a spatial and temporal perspective. General equations from the unit commitment problem are very similar,

with the exception that investment options are disregarded and that all modelled years are considered.

**Zonal prices are then obtained as a dual variable in the solving process, in addition to detailed dispatch outcomes for all considered time steps.** This simulation process nonetheless requires a **preliminary network reduction step** in order for the model to provide accurate zonal dispatch behaviour with coherent input time series. This aspect will be further explored in the next section with the construction of an updated case study.

### 5.1.2 Elaboration of a New Case Study.

As thoroughly detailed in Chapter 3, there is a **strong technical connection between clustering-based network reduction and the automated delineation of alternative zone configurations.** In fact, they both rely on the identification of bus clusters with minimal internal congestion.

**The alternative bidding zones obtained in Chapter 3 therefore define our clusters for network reduction.** The two remaining steps are therefore:

- 1) The **cluster aggregation of generation and demand data;**
- 2) The **modelling of accurate interconnection dynamics.**

We based this case study on **three candidate zone configurations** that have already been presented in Chapter 3: the **Status Quo delineation** and the **Zone Shuffle and Big Country Split configurations obtained with the connected weighted Hierarchical method (c-wH).** This clustering approach was indeed proved to offer best performance in terms of congestion management. These three configurations are presented in Table 5.1.

The “Regionalized System” trend was not retained for this case study as we showed in Chapter 4 that the corresponding configurations tend to dramatically affect market dynamics while not securing robust gains in congestion management. In that sense, the “Regionalized System” trend therefore mostly represents an amplification of the “Big Country Split” effects.

Table 5.1: A Synthetic View of the considered reconfigurations (Map source: OpenStreetMap.org.)

Maps	Main Revisions	Number of Zones	Number of borders
 <p data-bbox="284 501 405 530">Status Quo</p>	-	23	45
 <p data-bbox="272 1010 416 1039">Zone Shuffle</p>	<p><b>Splits:</b>            DE: 3 zones            IT: 2 zones            PL: 2 zones</p>	23 (=)	44 (-1)
 <p data-bbox="245 1520 440 1550">Big Country Split</p>	<p><b>Splits:</b>            DE: 3 zones            FR: 2 zones            IT: 2 zones            PL: 2 zones</p>	28 (+5)	58 (+13)

In particular, the selected “Zone Shuffle” and “Big Country Split” configuration rely on rather simple zone amendments that are **reminiscent of reconfigurations previously examined by ENTSO-E and ACER** in previous Bidding Zone Review initiatives (ENTSO-E, 2018b; ACER, 2022a). They are also **illustrative of two distinct approaches to Pan-European bidding zone revision**: a **combination of splits and mergers** that results in a similar number of zones on the one hand, and an approach relying on **numerous zone splittings** on the other.

We built our reduced model based on our full European static grid model for the 2025-2040 period, in alignment with “National Trends” scenario of ENTSO-E’s TYNDP 2020 (see Chapter II). **Generation capacities were aggregated according to the types of resources presented in Section 4.3.** Thermal generation technologies include traditional and CHP units powered by gas, hard coal, lignite or oil, gas and oil-powered combustion turbines, and nuclear units. Fatal generation is represented by hydro run-of-river, onshore and offshore wind and PV.

Nonetheless, the TYNDP 2020 data is only available for specific winter and summer dispatch intervals. In Chapters 2-4, we have been able to present diversified DC-OPF simulation results based on series of representative renewable generation scenarios, yet this is not sufficient to reconstruct **realistic and coherent time series at a Pan-European level.**

We therefore incorporated **data provided with ENTSO-E’s European Resource Adequacy Assessment (ERAA)**(ENTSO-E, 2021c), which are extracted from ENTSO-E’s Pan-European Market Modelling Database and Pan-European Climate Database (ENTSO-E, 2021c). The ERAA 2021 data includes historical time series for the 1982-1986 period and at a national level, which were updated for 2025 and 2030 climate projections. In particular, we used hourly time series for demand, PV, wind and hydro run-of-river generation as well as weekly reservoir inflows and pumped storage state of charge.

National assumptions on generation costs and capacity factors were **fitted to new clusters in proportion to the number of nodes.** A

bidding zone containing an equal proportion of buses from two countries will therefore be assigned average generation costs and renewable capacity factors. On the other hand, **demand times series were assigned according to nodal load key distributions** provided in TYNDP data. We applied 2025 ERAA time series to the 2025-2029 period while the 2030 database was used for years 2030 to 2040.

As mentioned in the previous section and in order to preserve the linearity of the model, **we aggregated hydro reservoirs and pumped storage into the same dispatchable generation capacities** with a weekly availability constraint, setting generation cost to the average zonal price obtained in previous DC-OPF simulations (see Chapter 4). While very simplifying regarding real-life hydro power valuation, this type of price assumption regarding hydro generation costs is often met in the literature on pan-European market modelling (Marinho *et al.*, 2017b; Felling and Weber, 2018; Lebeau *et al.*, 2021).

Table 5.II: Main capital cost assumptions.

Type of Power Plant	Fixed O&M Cost (k€/MW)	Investment Cost (k€/MW)
Coal	13	
Gaz_CCGT	13	
Oil	13	
PV	14	627
Coal_CHP	15	
Gaz_OCGT	15	770
Oil_CHP	21	
Onshore_Wind	21	1066
Hydro_RoR	21	
Nuclear	43	
Offshore_Wind	43	2843
Hydro_Reservoir	43	

The fixed operation and maintenance expenses and investment costs were taken from ENTSO-E's TYNDP 2020 (ENTSO-E, 2020a), and are summarized in Table 5.II. Annualized investment costs were derived for a lifetime of 30 years.

**Two main methods can be identified regarding interconnection constraints between clusters**, which echoes the distinction between Available Transfer Capacity and Flow-Based Market Coupling. In (Marinho, 2018), Marinho proposes an optimization method to identify equivalent power transfer distribution factors for the reduced model based on line flows from previous DC-OPF simulations. On the other hand, **institutional pan-European market simulations still tend to rely on ATC assumptions**. In particular, the ENTSO-E's ERAA 2021, which assesses resource adequacy for 2025 and 2030 horizons, relies on average annual ATCs, even though assumptions regarding flow-based modelling were nonetheless examined (ENTSO-E, 2021b).

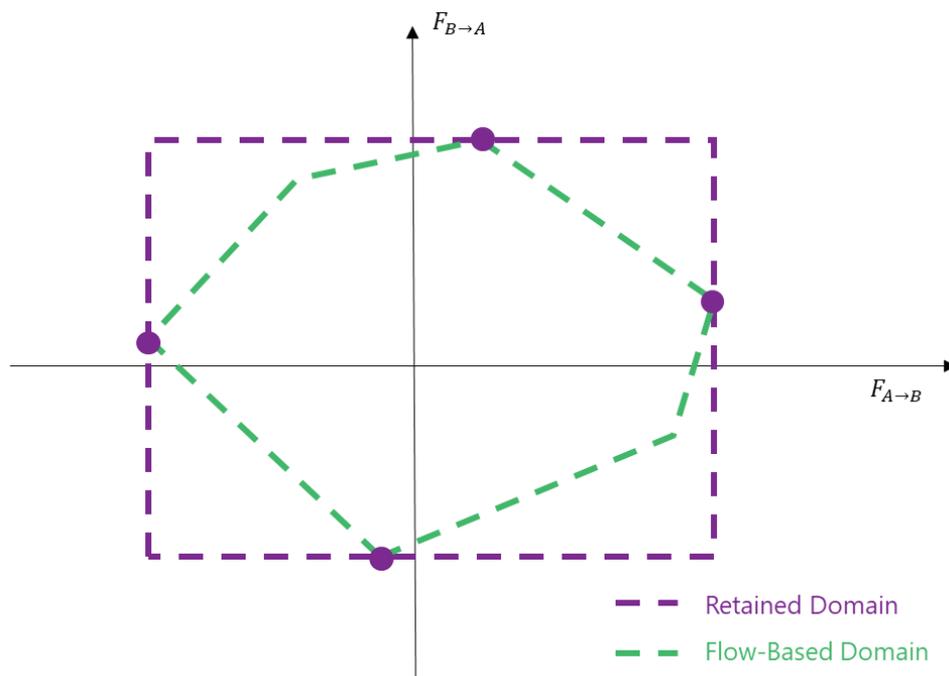


Figure 5.2: Example of Retained Domain Regarding Cross-Zonal Exchanges

In this case study, **existing simulation modules only allowed interconnection constraints in the form of annual ATC values**. In order to comply with this data format, we opted for a trade-off by **extrapolating annual ATC values from power flows of the DC-OPF simulations conducted in Chapters 3 and 4**. We defined exchange capacities as extreme values observed for the oriented cross-zonal flow on a given border and in all dispatch scenarios. Capacities obtained for 2025, 2030 and 2040 OPF simulations were respectively applied to the years 2025-2029, 2030-2039, and 2040.

While it disregards the interaction between interdependent borders, this simplifying approach **at least partially integrates structural cross-zonal constraints and the possible asymmetry of exchange capacities depending on the orientation of flows between two countries**. A representation of the retained interconnection domain is provided on Figure 5.2, based on the illustration of the Flow-Based method provided in Chapter I. The general evolution of total exchange capacities at system level is also presented in Table 5.III.

Table 5.III: Evolution of cross-zonal exchange capacities based on 2025 levels.

Zone Configuration	2030	2040
Status Quo	+44%	+71%
Zone Shuffle	+45%	+72%
Big Country Split	+50%	+78%

Finally, an illustration of the simulation chains presented in Chapters 2 to 5 is presented in Figure 5.3, and shows **the articulation of modelling frameworks like DC-OPF simulations, Generation Expansion Planning and Unit Commitment**. While the main modelling steps correspond to existing tools, like Digsilent's Powerfactory for the OPF simulations (DigSilent GmbH, 2020) or the simulation chain notably developed by Lebeau *et al.* (Lebeau *et al.*, 2021), our modelling contribution resides in **the development of ad-hoc simulation modules to articulate these frameworks**.

In particular, our original developments include **the enhancement of LMP-based clustering methods** with geographical metrics, the **application of a zonal merit order** to the resulting zone configurations and on a **network reduction step** that secures coherent modelling assumptions between both branches of the simulation chain.

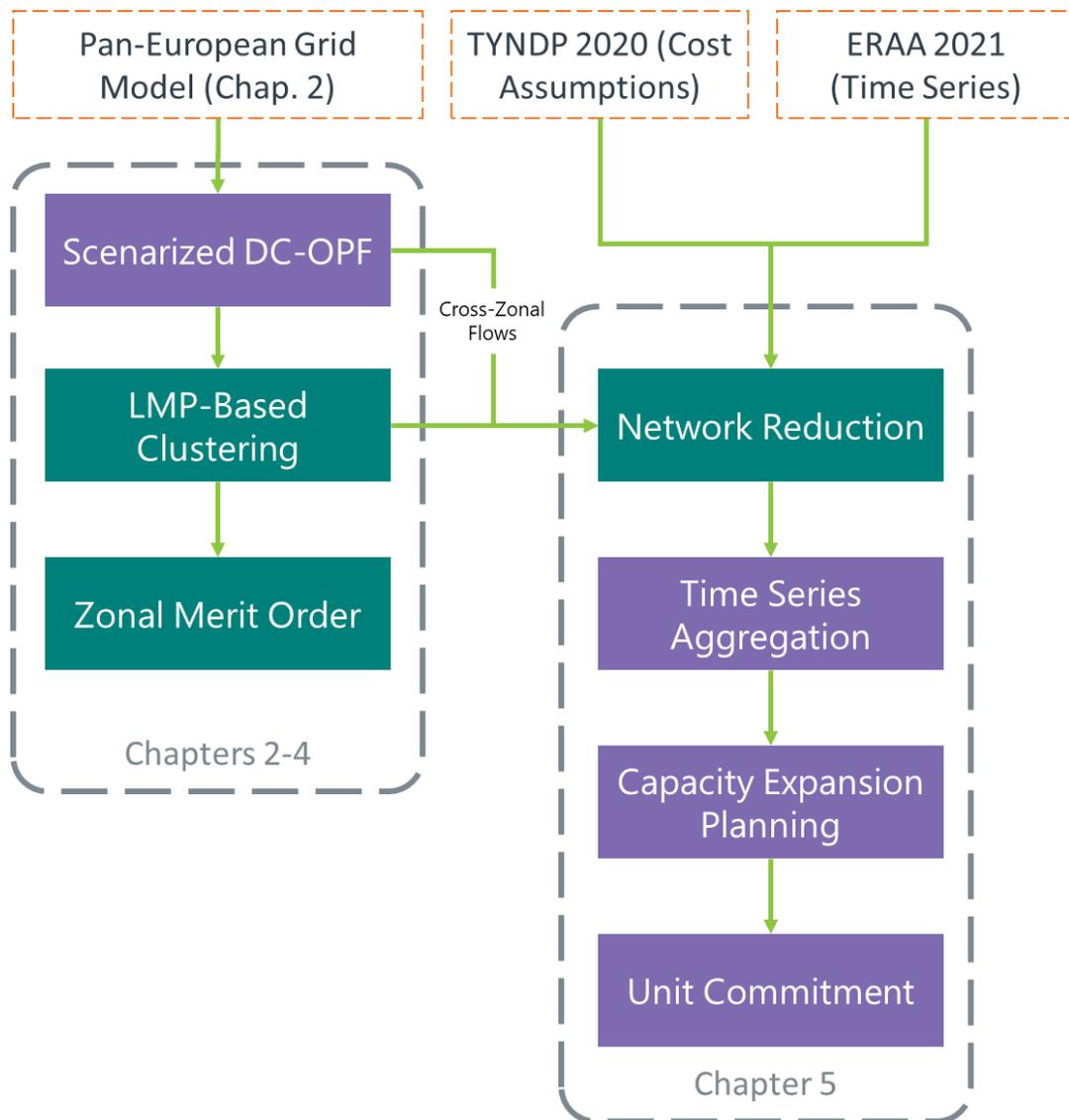


Figure 5.3: Overall articulation of the Simulation Chains.  
(Modules in purple correspond to pre-existing tools)

## 5.2 AN EXTENDED MULTI-HORIZON ANALYSIS OF MARKET DYNAMICS

We first ran the simulation process **without investment options** to address the articulation of our candidate zone configurations with the reference National Trends trajectory. This TYNDP system evolution scenario will be noted “NT” in the remainder of this work. The Generation Expansion Planning (GEP) module was therefore skipped and the Unit Commitment module was applied to the sixteen years between 2025 and 2040.

We set **a target of 50 representative days** in the Time Series Aggregation step based on the historical data provided in ERAA 2021 (ENTSO-E, 2021c). Unit Commitment results were therefore computed for 1,200 representative dispatch scenarios on each simulated year, an full annual results were then reconstituted based on the weighting of each representative day. Consecutive optimization problems were solved using IBM’s CPLEX (IBM ILOG, 2017) with an Intel® Xeon® Platinum 8260 processor at 2.40GHz. Runtimes are provided in the beginning of Section 5.3.

Most of the indicators presented in this section and the remainder of this chapter are normalized respectively to status quo levels. Considering the number of dispatch scenarios for each year and in the absence of further notice, we regard as significant any relative variation of 1.5% or more.

### 5.2.1 Generation and Interconnection Dynamics

In this section, we provide an insight into **how bidding zone revision affects operational dynamics regarding generation and cross-zonal exchanges**, based on a simple “National Trends” trajectory.

Figure 5.4 introduces the **energy mixes** obtained for target years 2025, 2030 and 2040. We present both a focus by fuel type and a distinction between renewable and thermal generation.

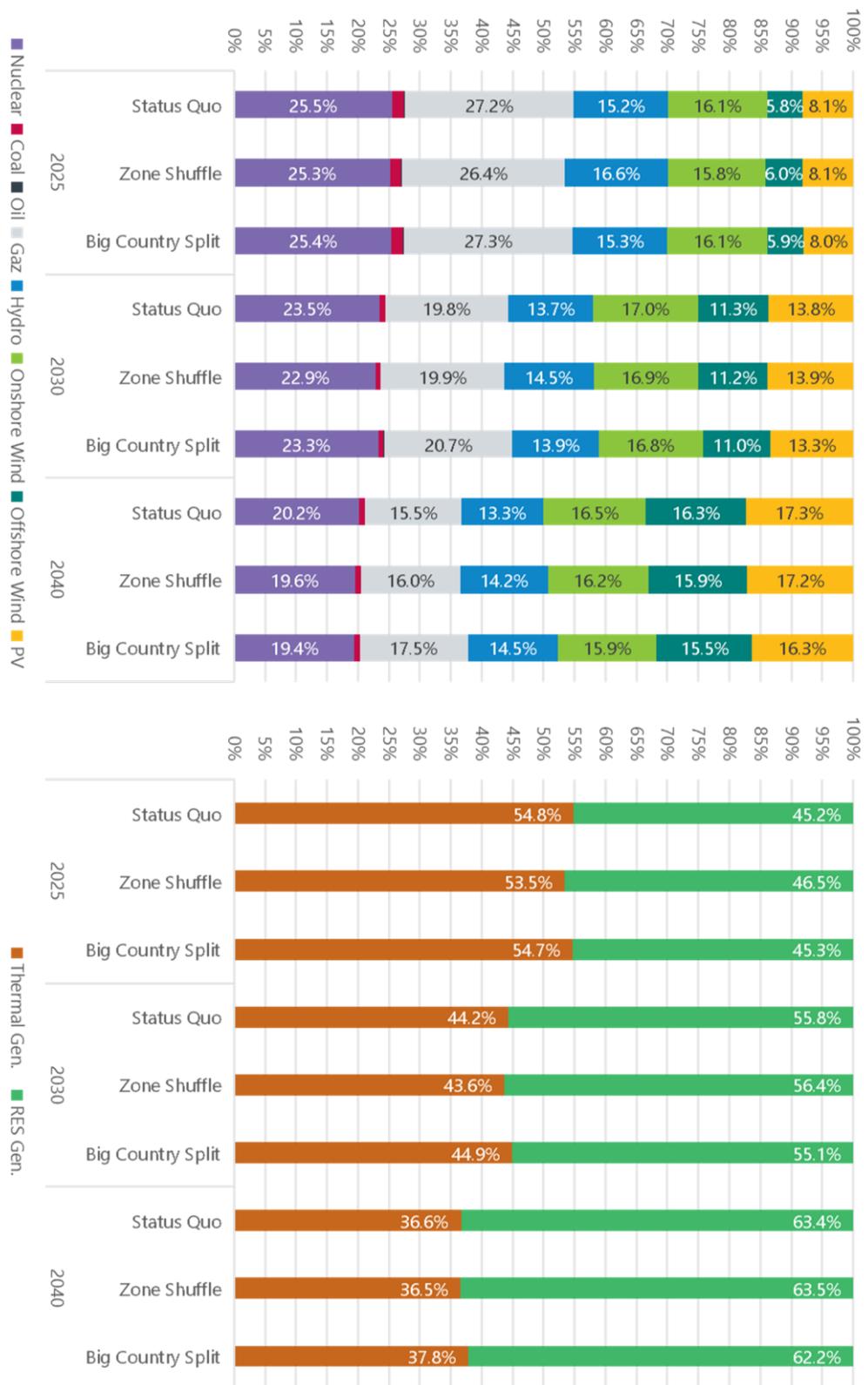
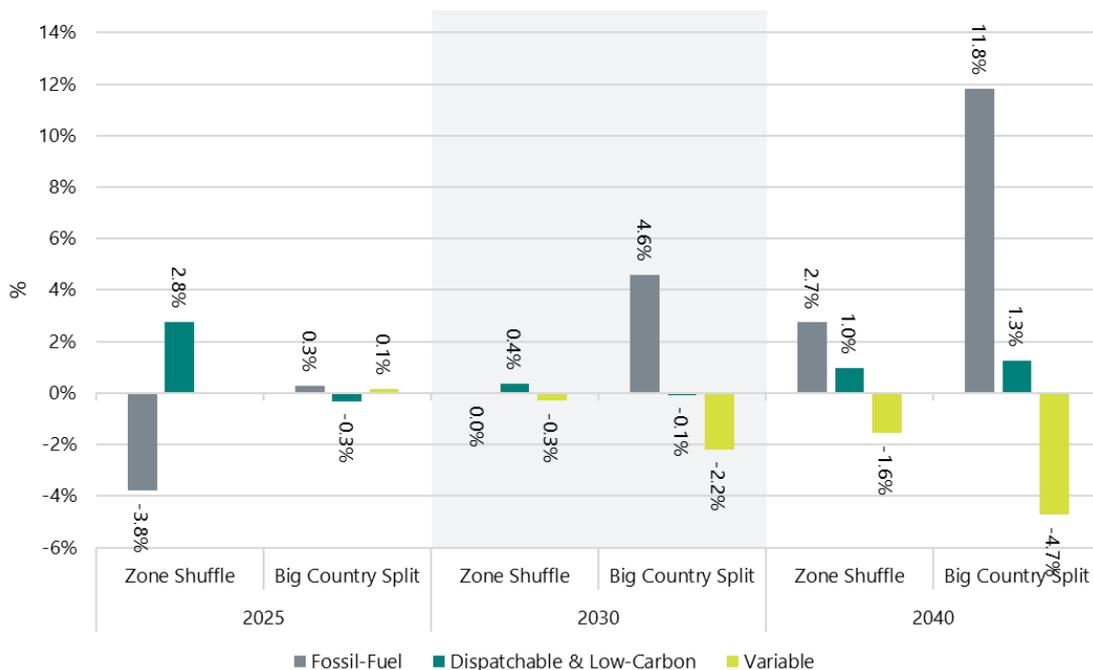


Figure 5.4: Evolution of Energy Mixes - With a Distinction of Renewable Versus Thermal Sources Penetration.

In this general overview, the overall share of each generation technology in the annual electricity production does not seem significantly affected by the considered zone revisions. This illustrates how, **in the short run, the energy mix is independent from the zone configuration**, and mostly determined by the installed generation assets.

However, on a more subtle note, the evolution of generation capacities is also influenced by **investment signals that result from market processes**, as further explored in section 5.3. This can also be anticipated in Figure 5.5, which presents the quantity sold for three types of generation assets: **fossil-fueled generation, dispatchable and low-carbon generation** (nuclear power plants and hydro reservoirs in this case study) as well as generation from **variable renewable energy sources** (i.e. wind, solar, and run-of-river assets). This can also be interpreted as an indicator of the liquidity of the different generation types.

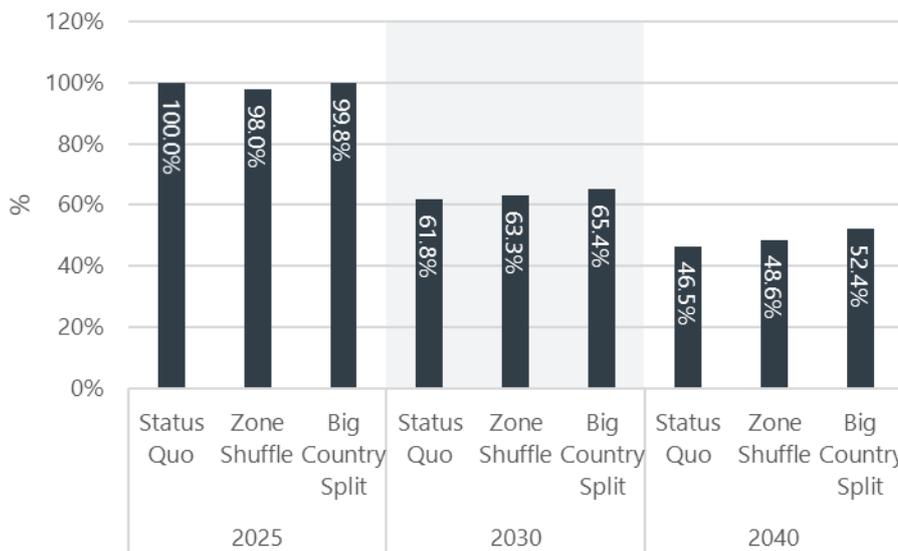


On a 2025 perspective, we observe that **the Zone Shuffle configuration tends to favor the dispatchable and low carbon assets (+2.8% in volume) over fossil-fueled generation (-3.8%), while the Big Country Split delineation tends to preserve the status quo**

**distribution of electricity sources.**

Nonetheless, **on a 2030 to 2040 perspective, the Big Country Split configuration tends to accentuate the liquidity of fossil-fueled units (respectively +4.6% and +11.8%) over fatal generation (with respectively -2.2% and -4.7%).** While the same dynamic is observed for Zone Shuffle in 2040, it is more mitigated overall, with +2.7% in fossil fuels and -1.6% in fatal generation. In particular, this shows that even though installed capacities are identical, alternative zone configurations produce distinct market outcomes for the different generation technologies – highlighting operational constraints that would be solved by curtailment and redispatching otherwise.

Moreover, this categorization of generation technologies may not be perfectly relevant regarding operating conditions – especially considering nuclear and hydro resources have very different dynamics. Nonetheless, it is a good proxy to **analyze the greenhouse gas emission levels associated with our candidate delineations.**



*Figure 5.6: Carbon Intensity of Power Generation - Normalized According to 2025 Status Quo Levels.*

Figure 5.6 represents the carbon intensity of electricity generation, computed in accordance with TYNDP assumptions (ENTSO-E, 2020c)

and normalized according to 2025 Status Quo levels. In particular, we chose an emission factor of 0.98 teq.CO<sub>2</sub>/MWh for coal-fired power plants, 0.77 teq.CO<sub>2</sub>/MWh for oil-fired plants and 0.43 teq.CO<sub>2</sub>/MWh for gas-fired plants.

The trends observed on Figure 5.5 are reflected on Figure 5.6: **in 2025, only the Zone Shuffle allows a significant decrease in the use of carbon-intensive technologies**, which translates into diminished carbon intensity (-2%). On the other hand, **in 2040, both alternative configurations tend to favor an increase of GHG emissions** (+2.1% and +5.9% respectively for Zone Shuffle and Big Country Split).

Moreover, let us note that these results have been obtained without additional generation expansion options, which means the content of the Pan-European generation fleet is the same for all three zone configurations – and aligned with ENTSO-E’s “National Trends” scenario for 2025, 2030 and 2040. **The observed differences in the penetration of competing power sources therefore result from diverging operational dynamics**, due to a different use of interconnection and a new distribution of demand curves and renewable generation profiles.

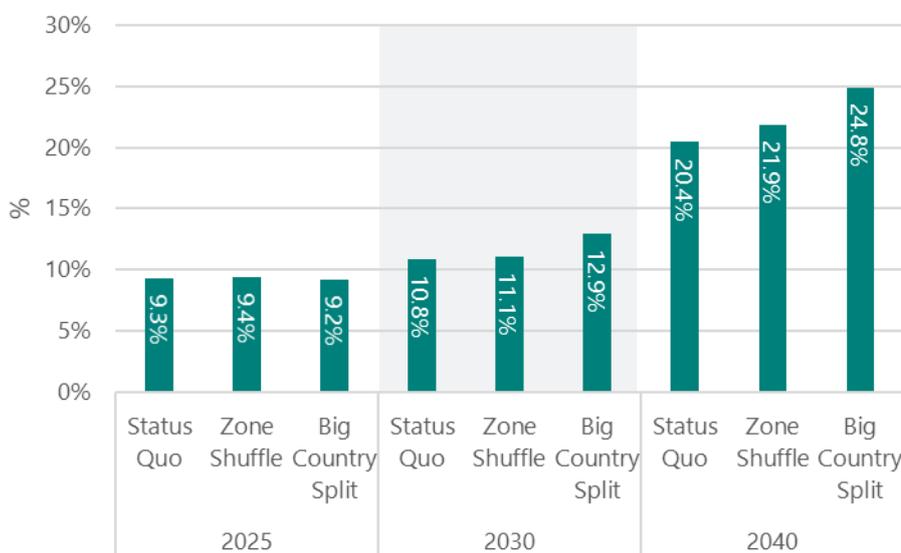


Figure 5.7: Annual Volume of RES Curtailment as a Proportion to the Total Fatal Generation.

In particular, Figure 5.7, representing the renewable curtailment volumes as a percentage of fatal generation, is reflective of the trends observed in Figures 5.5 and 5.6. **The Big Country Split configuration results in a increased level of curtailment in 2030 and 2040, which corresponds to a lower penetration of fatal generation.** On the other hand, the Zone Shuffle configuration preserves similar RES curtailment levels in 2025 and 2030, before an increase in 2040.

On a complementary perspective, these different levels of curtailment needs **are to be linked to the general use of interconnection capacities**, as pictured in Figure 5.8. In fact, **in the long run, the Big Country Split configuration is associated with both a higher level of curtailment and a lower use of cross-zonal capacities**, while **the Zone Shuffle candidate maintains an equal or superior level of interconnection use.**

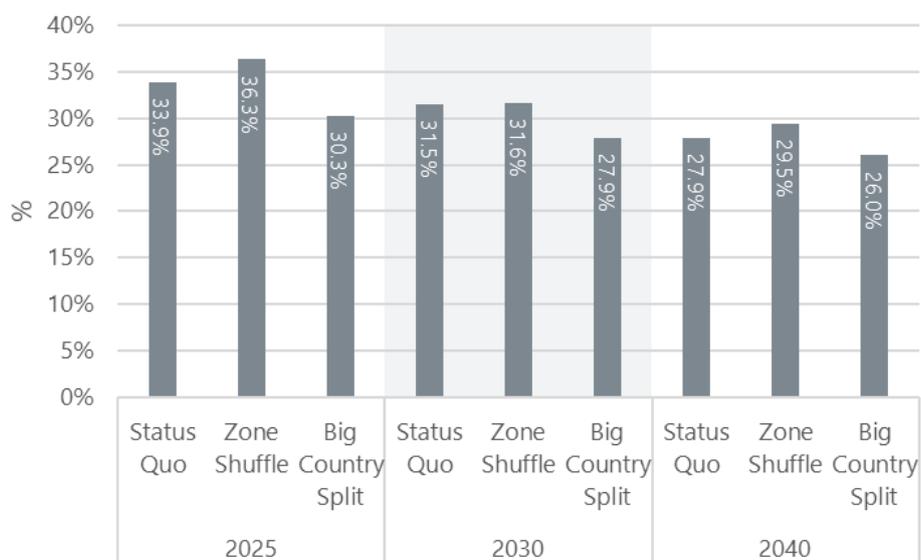


Figure 5.8: Average Use of Interconnections - Volume of Cross-Zonal Exchanges as a Proportion of Total Exchange Capacity.

In relation to the Chapter 4 finding that redispatching gains from zone revision are similar for all three configurations at horizons 2030 and 2040, we can conclude that the kind of zone splittings featured in **the Big Country Split configuration tends to create market coupling constraints that are inaccurate or too restrictive regarding the**

**actual congestion map. In particular, this tends to be detrimental to the penetration of fossil generation.**

Nonetheless, as developed in Chapter 1, bidding zone reconfiguration is also deeply associated with **a will to enhance the level of interconnection between European countries** – besides the underlying zone configuration. This notably echoes the objective set by the European Commission in 2014, stating that **by 2030, each country should have in place interconnection cables with a nominal capacity that represents at least 15% of the domestic generation capacity** (European Commission, 2017).

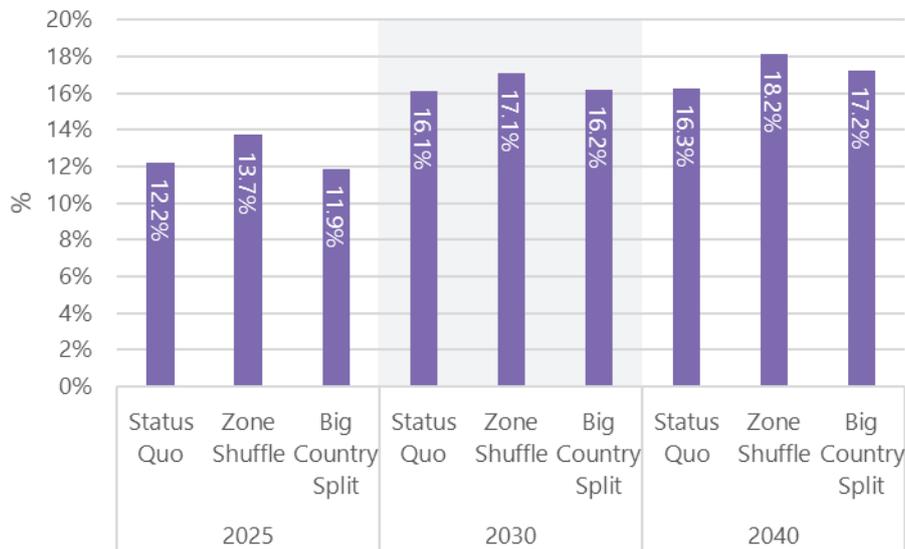
This criterion has been complemented in 2017 by experts from the European Commission. Three criteria are cited: each country should dispose of nominal interconnector capacities that represent 30% of the installed RES capacity, 30% of the demand peak and average price spreads should not exceed 2€/MWh on each border (European Commission, 2017).

Apart from the price spread criteria that will be discussed in Section 5.2.2, these indicators mostly focus on installed physical capacities, **which may be quite decorrelated with real-life operating conditions**. In particular, calculated cross-zonal exchange capacities tends to be significantly lower than the mere sum of interconnection line ratings, which is a main rationale behind the enforcement of the CEP70 criteria (see Chapter 1).

Moreover, in this case study, interconnection nominal capacities and installed generation capacities are fully determined by input model and data, which include line ratings, demand peaks and generation capacities. We therefore chose to characterize the cross-country interconnection level through **an indicator that is derived from the original 2014 criteria, yet based on electricity volumes**.

In particular, we focused on cross-country zone borders, which excludes borders between subzones of a same splitted country. Our **Interconnection Level indicator** is therefore defined as **the ratio between the total volume of cross-country exchanges and the total generation in the system over a year**. The results are presented

on Figure 5.9.



*Figure 5.9: Interconnection Level - Volume of Cross-Country Exchanges as a Proportion of the Total Annual Generation.*

While Figure 5.8 showed that the Big Country Split configuration tends to decrease the average use of interconnections, the average interconnection level between countries is here preserved at Status Quo levels. The cross-country interconnection level is even increased by the Zone Shuffle configuration at horizons 2025 (+1.5%) and 2040 (+1.8%). Regardless of the general use of interconnection, **only the Zone Shuffle configuration therefore seems to significantly enhance cross-country cooperation.**

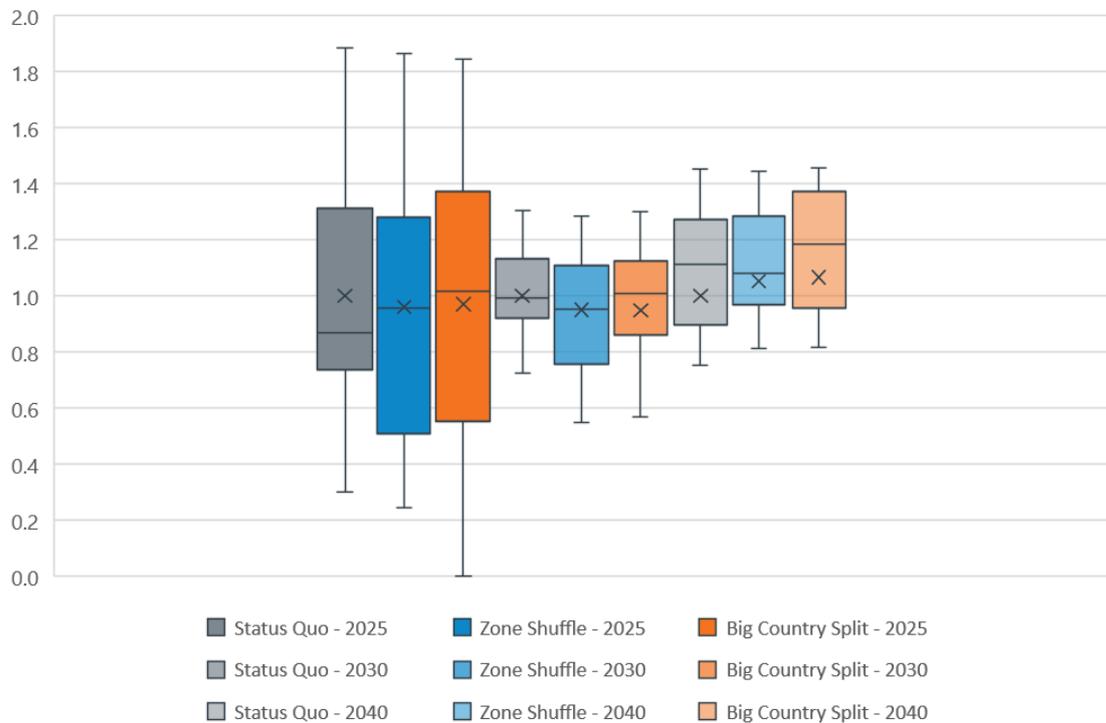
In this first approach, we see emerge a **general picture where the formation of more zones induced by the Big Country Split scenario tends to affect the penetration of low-carbon energy sources while not offering robust benefits for interconnection dynamics.**

On the other hand, **an adequate balance of zone mergers and splits can foster encouraging interconnection dynamics with limited impact on low-carbon sources.** These observations will be reevaluated in Section 5.3.2 in the light of generation and grid expansion.



## 5.2.2 Price Formation and Redistributive Effects

As explored in Chapter 4, a revision of bidding zones is likely to significantly affect market dynamics. This new case study was therefore an opportunity to complement previous findings with extended series of representative and coherent market equilibrium scenarios. In this context, we once again measured standard deviations of zonal prices for the 2025, 2030 and 2040 horizons. The general distribution of zonal volatilities across the whole system is presented in Figure 5.10.



*Figure 5.10: Distribution of Annual Zonal Price Volatilities - Standard Deviations Normalized According to Status Quo Levels.*

In 2025 and 2030, both the Zone Shuffle and Big Country Split configurations help to reduce the average price volatility, yet they tend to increase the heterogeneity of price variabilities between zones. In fact, we observe a decrease of the first quartile in both cases, which suggests decreases of price volatility for a significant number of zones.

In the Big Country Split case, this is nonetheless associated with an increase of the third quartile in 2025 and 2040. It therefore becomes explicit that **the Big Country Split configuration tends to increase the occurrences of high volatility values over all zones**. This is coherent with the findings of Chapter 4, and shows how **the formation of smaller zones may deteriorate the stability of prices for specific regions in the long run**.

While the general variability of prices affects investment signals, ACER specifically identifies **the correlation of spot prices between zones as determining for risk management on forward markets** (DNV GL Energy, 2020). In particular, price correlation allows market participants to perform hedging through combination of forward contracts in multiple bidding zones – that are not necessarily adjacent. In particular, it is proven that a perfect correlation of prices between two zones tends to allow the most efficient hedging while decorrelation increases the price risk for market player.

Even though an analysis of zone-to-zone price correlation is difficult to illustrate at system-wide scale, let us nonetheless introduce **an indicator for the spatial variability of prices in the system**. For each market interval of the considered years, we therefore computed **the interquartile range of the zonal prices observed in the system**, which can be envisaged as a **system-wide price divergence**. The annual distribution of this indicator for all market intervals is presented on Figure 5.11. In particular, heterogeneous values for price divergence during the year suggest lower price correlation overall.

We observe that the price divergence of the Status Quo and Big Country Split configurations are similar on a 2025 to 2030 basis, yet price divergence values tend to spread out in 2040 for the Big Country Split Case. The Zone Shuffle scenario is more ambivalent: the box plot becomes tighter in 2025, before a pronounced spread in 2030, then in 2040 the distribution is an intermediate between Status Quo and big Country Split results.

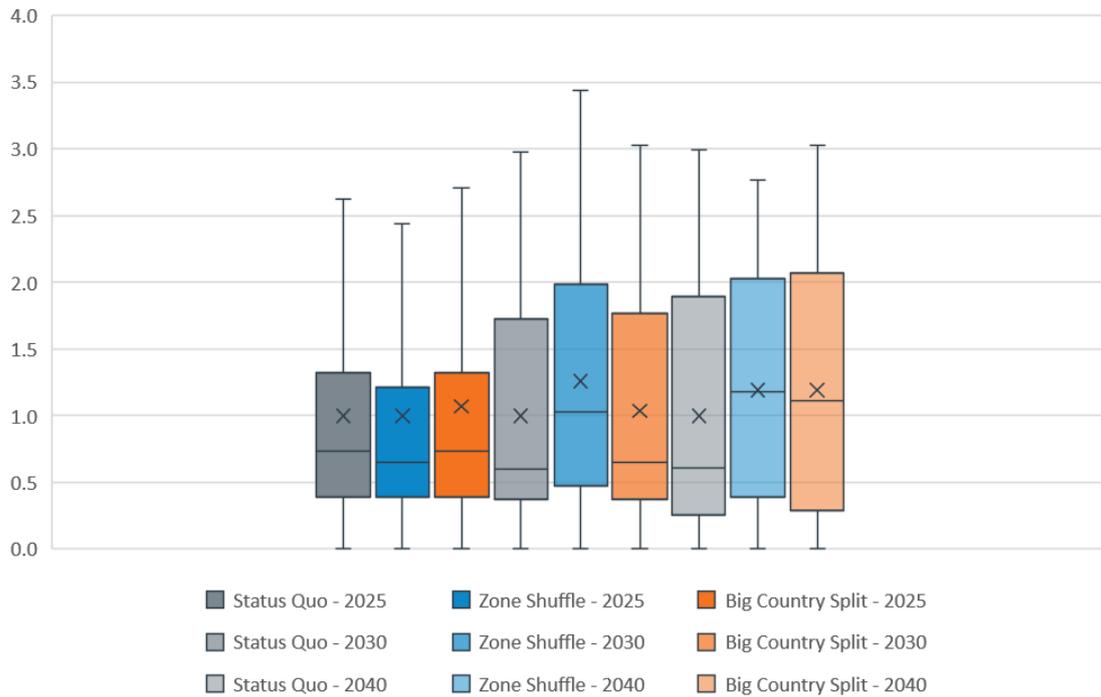


Figure 5.11: Annual Distribution of System-Wide Price Divergence - Normalized According to Status Quo Averages.

**The Zone Shuffle configuration therefore seems to be the only one to offer opportunities for more efficient hedging on forward markets in the short run** – provided the zone reconfiguration can be anticipated by market players before 2025. However, **this gain is not robust in time** and even leads to less performant dynamics than Big Country Split in 2030.

Nonetheless, these considerations on price correlation are independent with the notion of price spread between neighbour countries, which is highlighted as an indicator for the level of interconnection in (European Commission, 2017). We therefore computed the average price spread between zones in all three zone configurations and time horizons, weighted with the volume of energy exchanged. The results are presented in Figure 5.12.

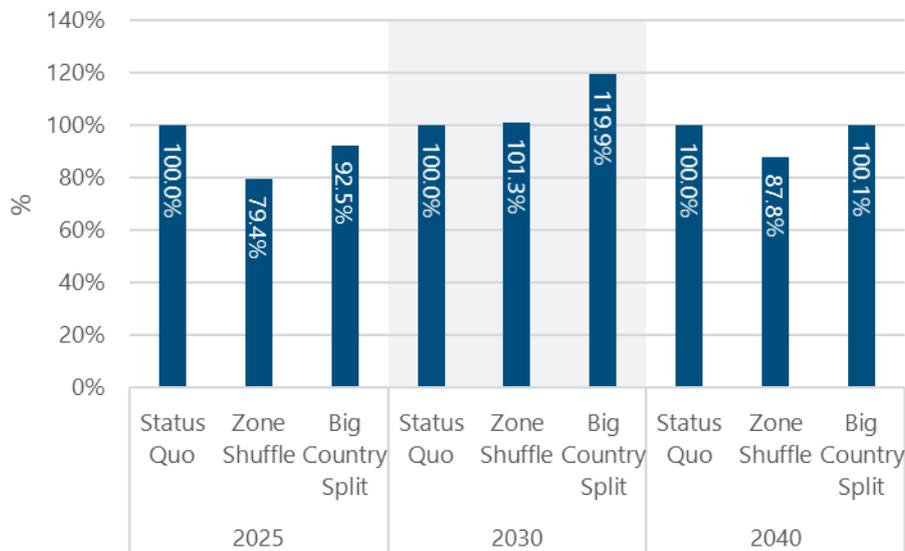


Figure 5.12: Average Price Spread Between Zones, Weighted According to Exchanged Volumes - Normalized According to Status Quo Levels.

First of all, these results are **coherent with the cross-country interconnection levels observed in Figure 5.9**, In particular we observed that the Zone Shuffle configuration increased the interconnection level in 2025 and 2040, and this also corresponds to a **decrease of average price spreads in the same periods**.

On the contrary, the Big Country Split does allow a reduction of the average price spread in 2025 while maintaining a similar volume of interconnection (see Figure 5.9), which suggests that it **creates a more performant distribution of cross-country exchanges compared to the Status Quo**. These results are nonetheless not robust to 2030 and 2040 dispatch conditions.

Finally, we have been able to analyse the economic transfer indicators presented in Section 4.1.2 under these more exhaustive market simulation results. While we have been able to explicitly compute the cost of consumption  $C_{cons}$ , producer margin  $\Pi_{prod}$  and the gross congestion rent  $Y_{TSO}$ , the net congestion rent  $\bar{Y}_{TSO}$  was not directly accessible since the simulation chain does not include redispatching processes. The computed variation of the three first indicators,

normalized according to the Status Quo level of consumption costs, is presented in Figure 5.13. We included the estimated variation of net congestion rents thanks to Equation (4.7) stating that  $C_{cons} - \overline{Y_{TSO}} - \Pi_{prod}$  is invariant under any zone configuration.

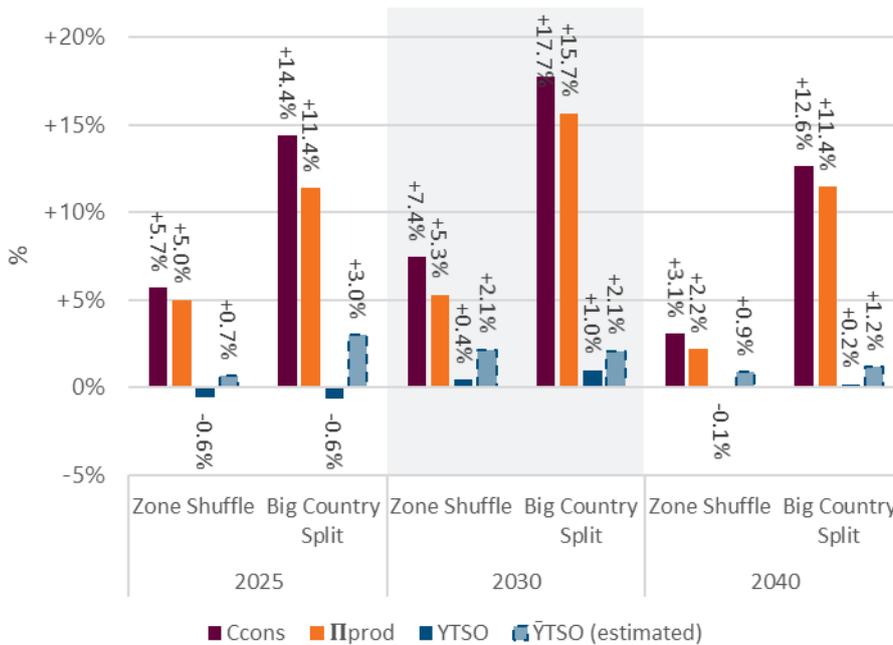


Figure 5.13: Redistributive Effects Between Producers, Consumers and TSOs - Normalized According to Status Quo Levels for Consumption Costs..

These results are coherent with the findings of the previous chapter: in the medium to long run, **configurations with smaller zones like the Big Country Split case tend to increase consumption costs due to higher producer margins and net congestion rents.** While the Zone Shuffle configuration also disrupts the status quo balance of costs and revenues, this phenomenon is more limited. Once again, it is observed that **only a small portion of the increased consumption costs is concretely converted in grid investment incitatives.**

The findings of Section 5.2 therefore tend to confirm and complement the diagnosis developed in the previous chapter. In the next section, we provide a final consolidation of this multi-dimensional and multi-horizon analysis, discussing **how generation investment dynamics and grid development interact with the observed trends.**

### 5.3 SENSITIVITY TO GENERATION EXPANSION AND CROSS-ZONAL CAPACITIES.

In this section, we explore **the sensitivity of previously established results to generation investment dynamics and grid development.** The previously explored system trajectory, which is our reference trajectory here, will be labelled “NT”, as a reference to the “National Trends” TYNDP scenario.

We therefore launched a new series of simulations, this time integrating **the four generation investment options described in Table 5.II**, namely gaz OCGT, PV, onshore and offshore wind. Each investment option was exclusively targeted to **bidding zones with existing installed capacity** for the corresponding technology. Under the assumption that a zone revision would occur just before 2025, we considered that system trajectories would not diverge in the short run and **we only allowed new investments for the years 2030 and 2040.**

The corresponding system trajectory, which includes an additional optimization of the generation fleet, will be noted “**NT+Opt.**”. Figure 5.14 shows the corresponding computing times.

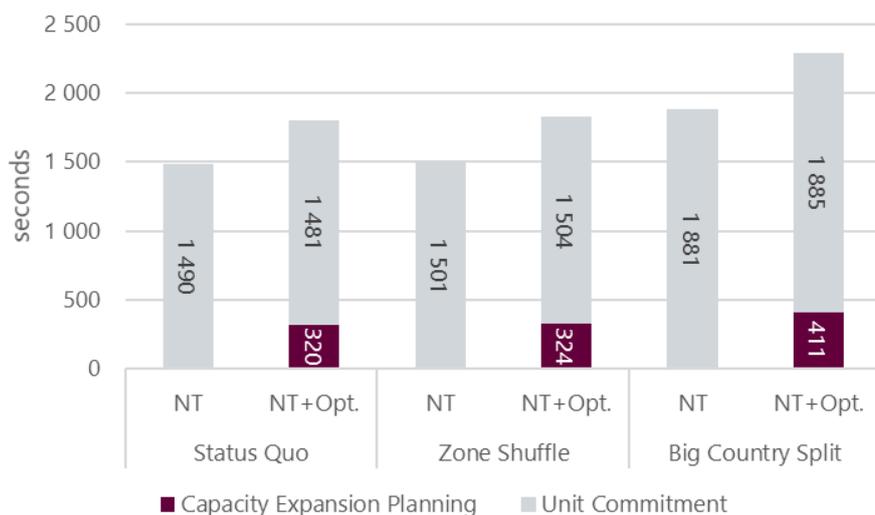


Figure 5.14: Total Computing Times For Each Type of Simulation.

In order to explore coordination potentials between these categories and future developments of the interconnections, we introduced homogeneous increases of all cross-zonal exchange capacities by 10% and 30%, for both 2030 and 2040 horizons. This resulted in **six main system trajectories: "NT", "NT+Opt.", "NT+10% Int.", "NT+Opt.+10% Int.", "NT+30% Int.", "NT+Opt.+30% Int."**.

Figure 5.15 introduces **the cumulated new generation capacities obtained in 2040 for the "NT+Opt.", "NT+Opt.+10%Int.", and "NT+Opt.+30%Int." trajectories**, and presented as a relative increase from the total 2040 generation capacity. We observe that onshore wind represents the major part of new capacities in all cases, which we attribute to our assumption on costs and capacity factors.

Nonetheless, these projections are mainly intended for illustrating how different zone configurations can induce diverging investment dynamics, and the resulting impacts on previously introduced indicators. In particular, realistic projections regarding the evolution of

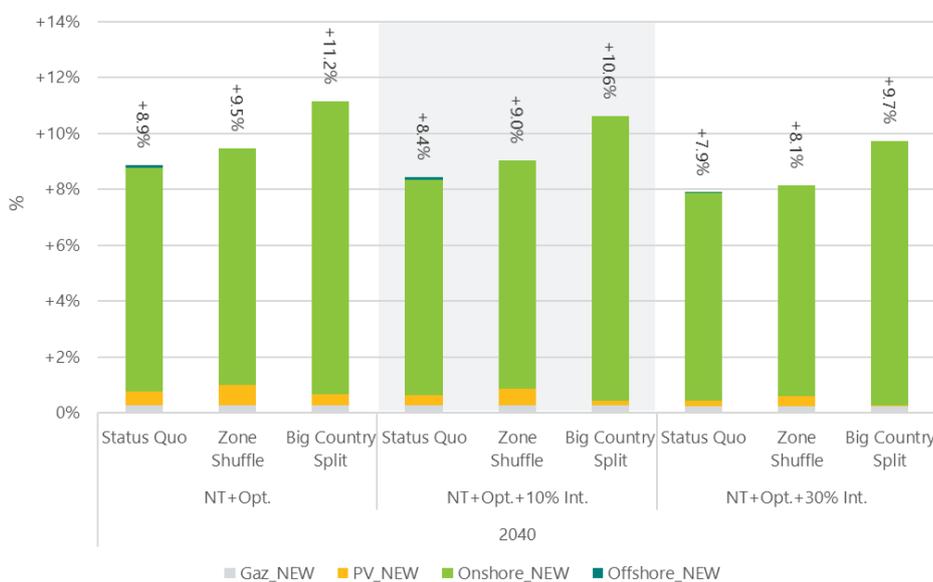


Figure 5.15: Additional Installed Capacities in 2040 - Normalized According to the Total 2040 Installed Capacity.

the generation fleet would require additional risk management modelling, which is not featured in our simulation chain.

From the perspective of a bidding zone revision, we note that **the Big Country Split configuration leads to significantly more generation expansion than the two other zone patterns**. However, **the introduction of additional cross-zonal capacity** in the “NT+Opt.+10%Int.”, and “NT+Opt.+30%Int.” trajectories **tends to narrow this gap and generally decrease the amount of new generation capacity**.

This observation directly echoes the finding of Section 5.2.1 that in the long run, the Big Country Split configuration favors both an increase of RES curtailment and a less efficient use of cross-zonal capacities. In particular, this suggests that **under a configuration with more zones, new generation capacities are more difficult to valorize at system scale, leading to more generation investments at the local scale**. In that sense, our results are coherent with the work of Grimm et al. (Grimm, Martin, Schmidt, *et al.*, 2016), who show that zone splittings can favor overinvestments.

In the remainder of this chapter, we will focus on **four main system trajectories**:

- The “**NT**” reference trajectory;
- “**NT+Opt.**”, which illustrates the impact of investment signals on the reference National Trends trajectory;
- “**NT+30% Int.**”, to address the impact of a massive expansion of cross-zonal capacities on the NT trajectory;
- “**NT+Opt.+10%Int.**”, to discuss how accurate generation investments can be articulated with more limited efforts regarding grid development.

In particular, our objective here is to address **how these long-term trajectories affect the differences of market dynamics between the Status Quo, Zone Shuffle and Big Country Split configurations**. We will therefore not focus on how status quo dynamics themselves are affected.

### 5.3.1 Generation and Interconnection Dynamics

In the previous section, we showed that **from a 2040 perspective, both the Zone Shuffle and the Big Country Split configurations tend to significantly decrease the penetration of fatal generation compared to the status quo.** This was already the case in 2030 for Big Country Split.

However, Figure 5.16, which echoes Figure 5.5, shows that this observation is **not necessarily robust to the considered system trajectories.** In fact, while the decrease observed for Zone Shuffle was barely significant (-1.7% in Figure 5.5), both the “NT+Opt.” and the “NT+Opt.+10% Int.” reduce this gap below the -1.5% uncertainty threshold, with -1.3% each. On the other hand, while generation investments tend to improve the relative penetration of electricity from fatal sources in the Big Country Split configuration, this level remains more than 3.5% lower than the status quo.

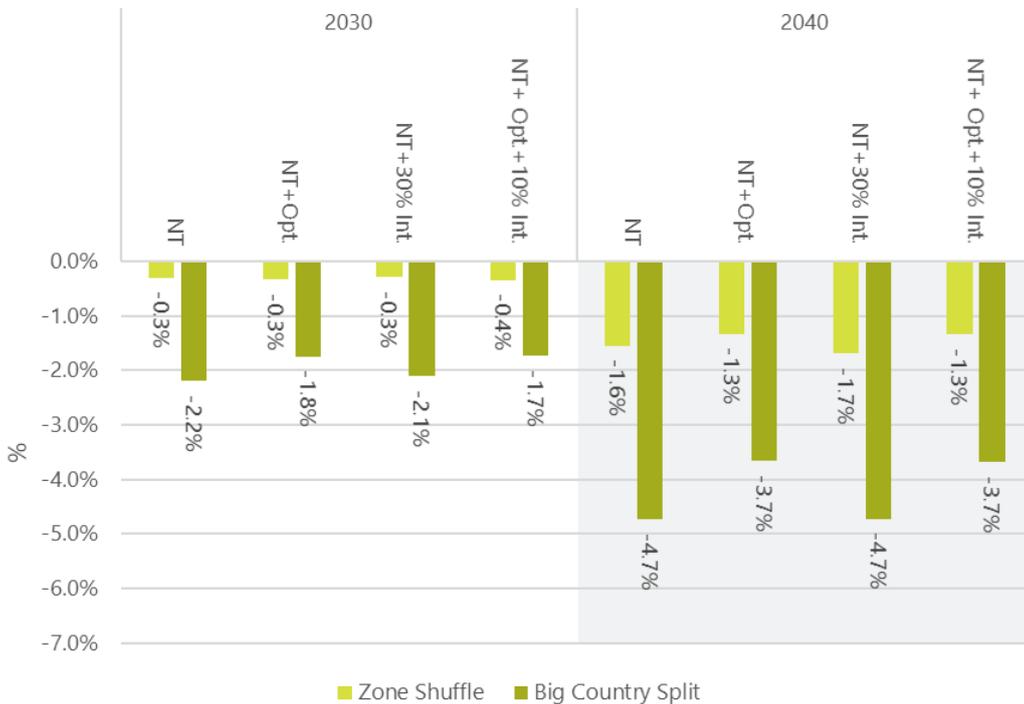


Figure 5.16: Annual Sold Volume for Fatal Generation - As a Relative Variation From the Status Quo Volumes.

This example shows that **an adequate combination of generation expansion and grid development can help reducing small deficiencies resulting from a zone revision**, like in the Zone Shuffle case, **yet not completely erase structural divergences** as observed in the Big Country Split case.

In particular, while our capacity expansion module tends to affect significantly more additional generation capacity to the Big Country Split configuration, this is not sufficient to reach the status quo penetration of fatal generation. In fact, this narrative is reinforced by Figure 5.17, which shows how the share of RES curtailment evolves in comparison to Status Quo levels (in relation with Figure 5.7).



Figure 5.17: Share of RES Curtailment in Proportion to the Total Fatal Generation Volume – In Comparison to Status Quo Levels.

In particular, the "NT+Opt." and "NT+Opt.+10% Int." trajectories leads to relatively more RES curtailment in the Big Country Split configuration, especially from a 2030 perspective. **In the Big Country Split case, additional fatal generation capacities results in relatively more curtailment, while the Status Quo and Zone Shuffle configurations tend to remain on an equal footing.** On the contrary, the "NT+30% Int." trajectory does not affect significantly RES curtailment levels, which indicates that **all three configurations are equally affected by an homogeneous enhancement of exchange capacities.**

More complex dynamics are nonetheless at stake regarding the use of interconnections, in particular from a 2040 perspective. Figure 5.18 presents the average use of interconnection capacities, as already featured in Figure 5.8.



Figure 5.18: Average Use of Interconnections - In Comparison to Status Quo Levels.

We observe that in 2040, the “NT+Opt.” trajectory helps increasing the relative use of interconnections in the Zone Shuffle configuration, and that the “NT+30% Int.” tends to narrow the gap. Our interpretation is therefore that, **regarding the use of interconnections, the consideration of generation investment trends is more beneficial to the Zone Shuffle system than to the Status Quo, while the Status quo benefits more from an increase of exchange capacities.** Similar dynamics are at stake regarding the Status Quo and Big Country Split configurations.



Figure 5.19: Level of Interconnection Between Countries - In Comparison to Status Quo Levels.

On a more simple note, **observations regarding the level of interconnection between countries (see Figure 5.9) are quite consistent between all system trajectories.** While the three zone configurations result in a similar level of interconnection in 2030, the Zone Shuffle

configuration allows a clear improvement in 2040. The corresponding variations are presented in Figure 5.19.

Finally, the carbon intensity of electricity generation can be interpreted as a summary of the previously described dynamics regarding generation and interconnection. In Section 5.2, Figure 5.6 presented the 2025 to 2040 evolution of carbon intensity as a percentage of 2025 Status Quo levels. Figure 5.20 shows how observed variations are affected by our four system trajectories.

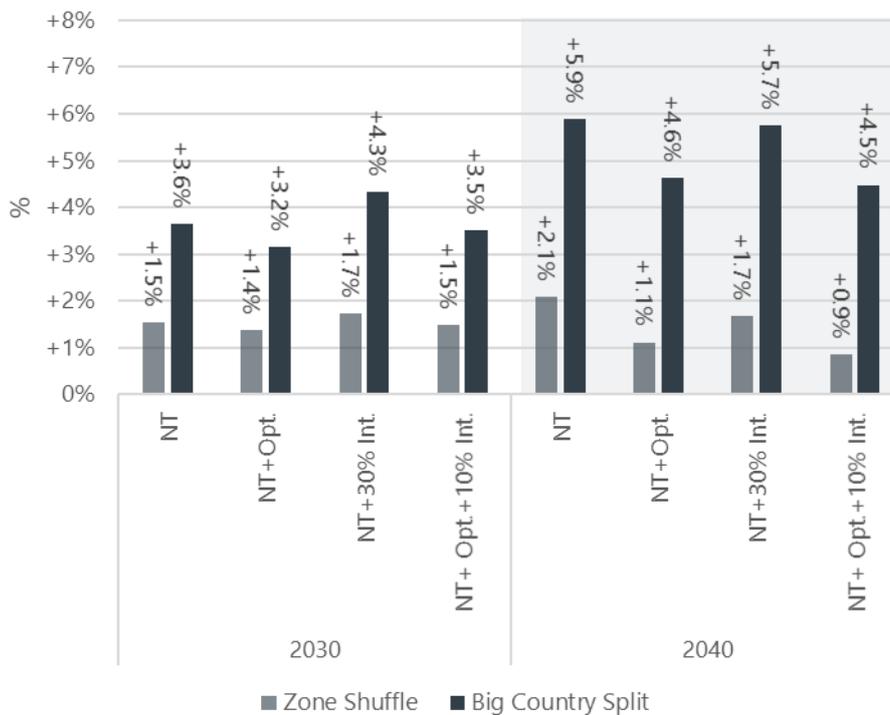


Figure 5.20: Carbon Intensity of Power Generation - In Comparison to Status Quo Levels, Normalized According to 2025 Status Quo Levels.

In 2030 and 2040, Big Country Split carbon intensities are consistently higher than Status Quo values. Nonetheless, while we previously observed that, in the NT trajectory, 2040 Zone Shuffle values are significantly higher than the Status Quo (+2.1%), the “NT+Opt.” and

“NT+Opt.+10% Int.” help narrowing the gap under the 1.5% uncertainty level (with respectively +1.1% and +0.9%). **In the Zone Shuffle case, an adequate combination of generation investments and grid development is therefore likely to secure a system trajectory that is compatible with reference decarbonation objectives.**

### 5.3.2 Price Formation and Redistributive Effects

In Section 5.2.2, we illustrated strong variations from one zone configuration to another regarding price formation and the distribution of costs and revenues in the system. These trends nonetheless appear **quite sensitive to diverging system trajectories**, as illustrated by the computation of the average price spread on borders between two countries.



Figure 5.21: Average Price Spreads Between Zones - In Comparison to Status Quo Levels.

Figure 5.21 presents an update of the results from Figure 5.12. While our previous 2030 observations seem robust to different system trajectories, 2040 results appear more sensitive. Regarding the Zone Shuffle configuration, while both the “NT + Opt.” and “NT+30% Int.” trajectories preserve a decrease of the average price spread, the “NT+Opt.+10% Int.” case brings this value very close to the Status Quo. **For this indicator, the coordination of grid and generation developments would therefore benefit more a Status Quo system than a Zone Shuffle configuration.**

On the other hand, the “NT + Opt.” and “NT+30% Int.” trajectories produce opposite effects on the 2040 Big Country Split average price spread, respectively with -10.6% and +9.8% compared to the Status Quo Level. Moreover, the “NT+Opt.+10% Int.” trajectories stabilizes

2040 Big Country Split average price spreads slightly below status quo levels. **Our four system trajectories therefore have clearly diverging impacts on the 2040 average price spreads of Status Quo and Big Country Split versions of the European power system,** with nonetheless an interesting potential for grid and generation investment coordination.

We also addressed the impact of our different system trajectories on redistributive effects between producers, consumers and transmission system operators. In particular, Figure 5.22, which complements Figure 5.13, shows the 2030 and 2040 variations of consumption costs induced by zone revision in all four system trajectories, highlighting the contribution of producer margins and net congestion rents.

From both 2030 and 2040 perspectives, we observe that under the "NT+Opt." and "NT+Opt.+10%Int." system trajectories, zone revision results in a more pronounced increase of consumption costs, yet the contribution of net congestion rents in this increase is lower. This suggests that TSOs face more important congestion costs, which scales down net congestion rents and strengthen the margin of producers. In other words, **under these scenarios with massive introduction of fatal generation resources, the Zone Shuffle and Big Country Split configurations make it more difficult for transmission system operators to obtain the revenues needed for grid development.**

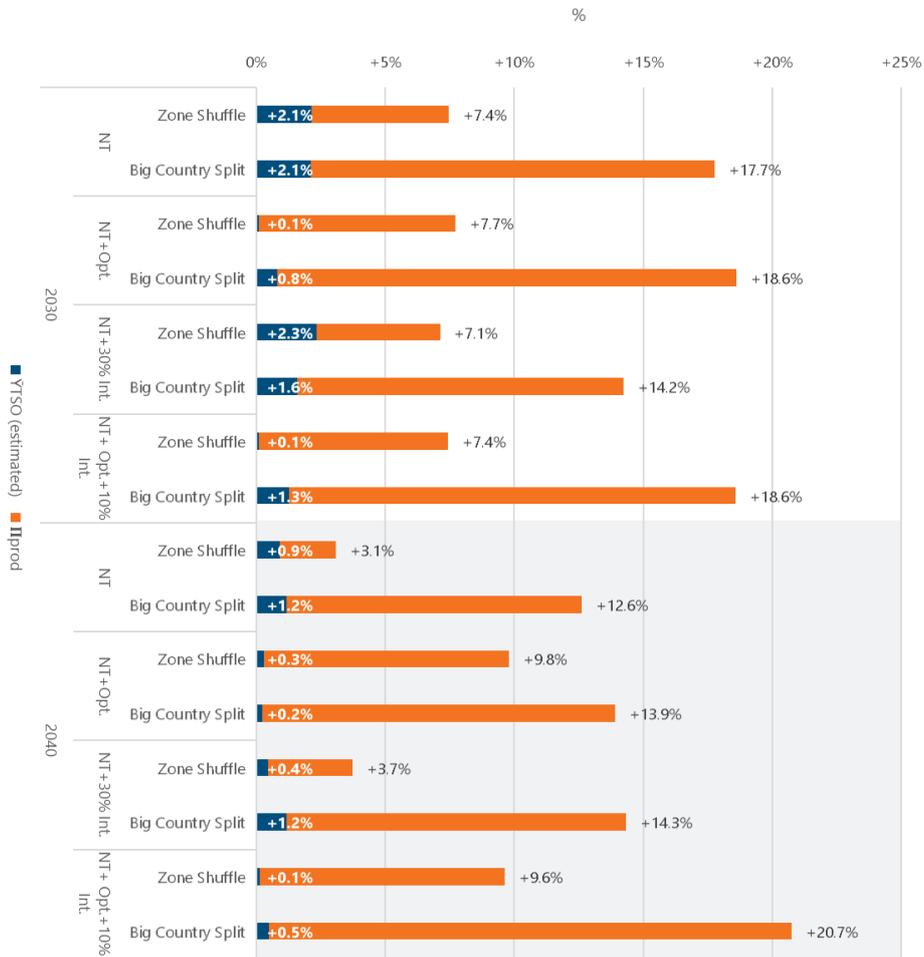
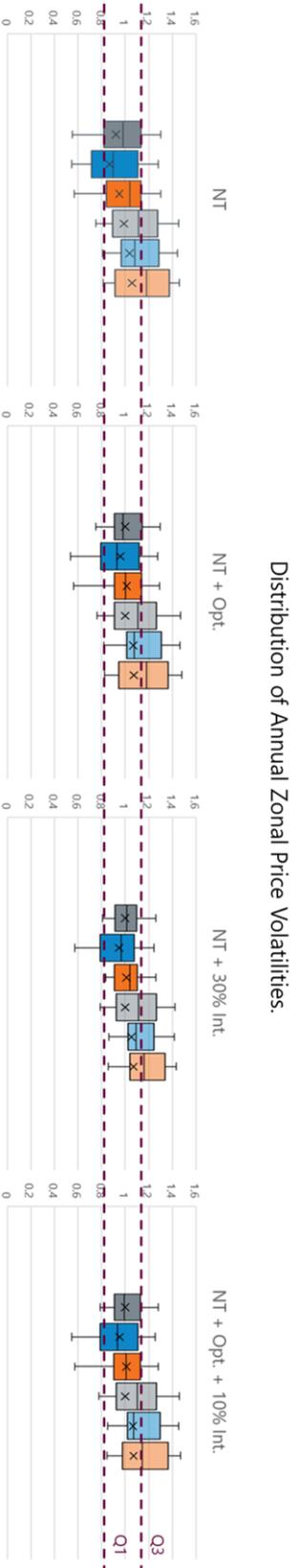


Figure 5.22: Contribution of Net Congestion Rents and Producer Margins to the Variation of Consumption Costs - Normalized According to Status Quo Levels of Consumption Costs.

Finally, Figure 5.23 presents the influence of system trajectories on the distribution of annual price volatilities over all zones, as well as the annual distribution of System-Wide Price Divergence. To ease comparison, we highlighted the levels corresponding to the first and third quartiles of "NT" Status Quo 2030 distributions.

In general, observations from Section 5.2.2 are consistent for all system trajectories. This is notably the case for zonal price volatilities, which seem to be impacted very similarly by zone revision in the four considered system trajectories.



Annual Distribution of System-Wide Price Divergence.

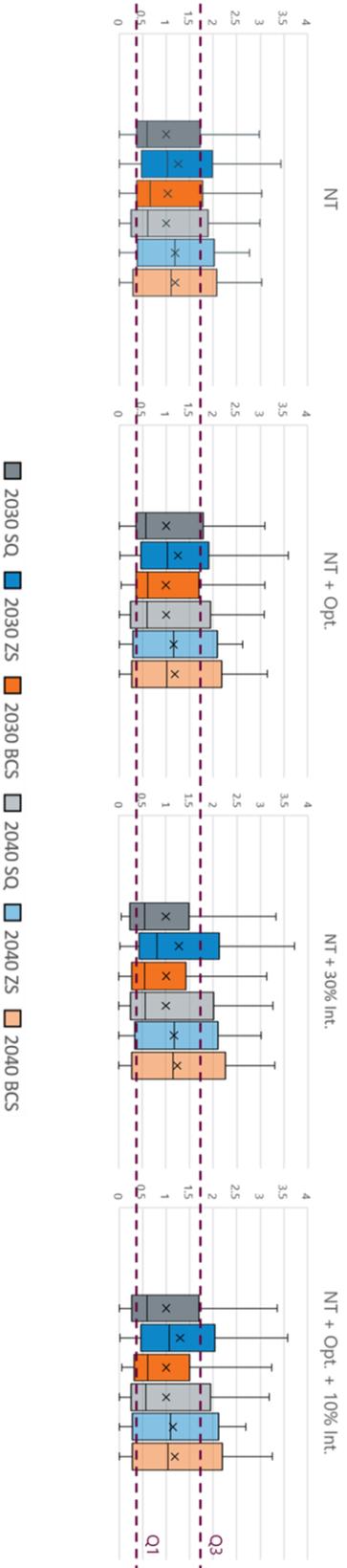


Figure 5.23: Sensitivity of Price Volatilities and System-Wide Price Divergence Under Our Four System Scenarios. Normalized According to Status Quo Levels

However, a significant exception can be noted regarding the 2030 distribution of system-wide price divergence for the Big Country Split configuration. In particular, it appears that system trajectories including a reinforcement on exchange capacities (namely “NT+30% Int.” and “NT+Opt.+10% Int.”) tend to significantly decrease the third quartile of these distributions. In other words, it seems that **under a Big Country Split configuration, the enhancement of cross-zonal exchange capacities helps significantly improve price correlation**, which we previously associated with more efficient risk management.

## 5.4 SUMMARY TABLE

Table 5.IV summarizes our observations regarding the 2025, 2030 and 2040 impacts of a Zone Shuffle and Big Country Split zone revision – in comparison to status quo performances. We also integrated 2030 and 2040 sensitivities to alternative system trajectories regarding generation expansion and cross-zonal exchange capacities. General observations will be developed in the Main Findings section below.

In compliance with our estimation of uncertainties, relative variations of less than 1.5% have been disregarded and marked as equal (=) to status quo performances. In addition, we made a distinction between strong variations of 3% or more, marked with the (--) and (++) symbols, and variations comprised between 1.5% and 3%, marked with (-) or (+).

Based on our case study, we chose to highlight synthetic criteria rather than the full set of metrics used in the previous sections. In particular, the observed distributions of system-wide price divergences has been transcribed in terms of price correlation, which affects risk management. We nonetheless referenced relevant figures within the table.

Some of the retained criteria may appear antagonistic, such as the penetration of fossil generation and RES curtailment levels. We nonetheless chose to make our (+) and (-) ratings correspond to objective variations from status quo performances rather than our own perception of what would be positive or negative for the European power system.

Table 5.IV: Chapter 5 Summary Table

Assessment Criteria	Generation and Interconnection Dynamics					Price Formation and Redistributive Effects						
	Integration of Fossil Generation	RES Curtailment	Carbon Intensity	Use of Interconnections	Interconnection Between Countries	Average Cross-Border Price Spreads	Average Zonal Price Volatility	Price Correlation	Consumption Costs	Producer Margin	Net Congestion Rent.	
Figure References	5.5; 5.16.	5.7; 5.17.	5.6; 5.20.	5.8; 5.18.	5.9; 5.19.	5.12; 5.21.	5.10; 5.23.	5.11; 5.23.	5.13; 5.22.	5.13; 5.22.	5.13; 5.22.	
Zone Shuffle	2025											
	National Trends	(=)	(=)	(-)	(+)	(+)	(-)	(-)	(++)	(++)	(++)	(=)
	2030											
	National Trends	(=)	(=)	(=)	(=)	(=)	(=)	(--)	(--)	(++)	(++)	(+)
	+ Generation Expansion	(=)	(=)	(=)	(=)	(=)	(+)	(--)	(--)	(++)	(++)	(=)
	+ 30% Cross-Zonal Capacities	(=)	(=)	(+)	(=)	(=)	(+)	(--)	(--)	(++)	(++)	(+)
	+Capacity Expansion +10% Cross-Zonal Capacity	(=)	(=)	(=)	(=)	(=)	(+)	(--)	(--)	(++)	(++)	(=)
	2040											
	National Trends	(-)	(=)	(+)	(+)	(+)	(-)	(++)	(--)	(++)	(+)	(=)
	+ Generation Expansion	(=)	(=)	(=)	(++)	(+)	(-)	(++)	(--)	(++)	(++)	(=)
	+ 30% Cross-Zonal Capacities	(-)	(=)	(+)	(=)	(+)	(-)	(++)	(--)	(++)	(++)	(=)
	+Capacity Expansion +10% Cross-Zonal Capacity	(=)	(=)	(=)	(+)	(=)	(=)	(++)	(--)	(++)	(++)	(=)
	Big Country Split	2025										
National Trends		(=)	(=)	(=)	(--)	(=)	(-)	(-)	(-)	(++)	(++)	(+)
2030												
National Trends		(-)	(+)	(++)	(--)	(=)	(++)	(-)	(+)	(++)	(++)	(+)
+ Generation Expansion		(-)	(++)	(++)	(-)	(=)	(++)	(-)	(+)	(++)	(++)	(=)
+ 30% Cross-Zonal Capacities		(-)	(+)	(++)	(--)	(=)	(++)	(-)	(++)	(++)	(++)	(=)
+Capacity Expansion +10% Cross-Zonal Capacity		(-)	(++)	(++)	(-)	(=)	(++)	(-)	(++)	(++)	(++)	(=)
2040												
National Trends		(--)	(++)	(++)	(-)	(+)	(=)	(++)	(-)	(++)	(++)	(=)
+ Generation Expansion		(--)	(++)	(++)	(=)	(=)	(-)	(++)	(-)	(++)	(++)	(=)
+ 30% Cross-Zonal Capacities		(--)	(++)	(++)	(-)	(=)	(++)	(++)	(-)	(++)	(++)	(=)
+Capacity Expansion +10% Cross-Zonal Capacity		(--)	(++)	(++)	(=)	(=)	(-)	(++)	(-)	(++)	(++)	(=)

## KEY FINDINGS - CHAPTER 5

In this section, we complemented the analysis of Chapter 4, **with a focus on two specific alternative zone configurations**. While not designed as realistic zone revision proposals these two candidate delineations are representative: a “Zone Shuffle” configuration that balances zone mergers and splittings on the one hand, and a **“Big Country Split” configuration with multiple zone splittings** on the other.

**We then designed three reduced versions of our large-scale European static grid model**, corresponding to the status quo zone delineation and our two alternative candidates. This step notably relied on **the estimation of cross-zonal exchange capacities** based of previously conducted DC-OPF simulations and the introduction of **2025 and 2030 projections of historical time series for renewable generation and demand**.

We also introduced a **complementary simulation chain that combines capacity expansion planning and unit commitment** frameworks, with a preliminary time series aggregation step. In comparison to the approach developed in Chapters 2 to 4, we have thus been able to **propose more realistic modelling of zonal market dynamics**, with more accurate representation of interconnection dynamics and the integration of investment decisions. Moreover, we went from generic input scenarios for renewable generation and demand to the **re-constitution of year-specific time series extracted from institutional system evolution scenarios**.

Our case study is finally structured in two main steps. First, we focus on **a reference system trajectory that corresponds to the “National Trends” TYNDP scenario**. Second, **we address the sensitivity of our observations to alternative system trajectories that combine additional generation investments and enhancements of cross-zonal exchange capacities**.

The results summarized in Table 5.IV show that **both the Zone Shuffle and the Big Country Split reconfiguration strongly affect the balance of costs and revenues in the system**. In coherence with the

findings of Chapter 4, the considered zone revisions are associated with **significantly higher costs for consumers in the short to long run**. Nonetheless, **only a very limited portion of this increase is effectively captured in the form of congestion revenue** that could be used by transmission system operators to reinforce the grid.

In particular, we observed in Section 5.2.2 that **the generation investment dynamics for 2030 and 2040 tend to deteriorate even further the opportunity for TSOs to generate net congestion incomes**. In Chapter 4, we also observed that 2025 redispatching gains are not robust in the medium to long run. This suggests that on a 2030 to 2040 basis, TSOs are burdened by high congestion costs under the three considered zone configurations. While bidding zone revision is often seen as a way to improve congestion management in the short term, **this new analysis casts strong doubt on the longer-term benefits, particularly in light of the implied pressure on consumers and the costs of a market design transition**.

Both the Zone Shuffle and Big Country Split configurations also have in common that even a significant expansion of cross-zonal exchange capacities has very limited impact on the observations made in Section 5.1. In other words, **the three considered zone configurations are equally impacted by grid reinforcement, thus none of them seems to create more efficient conditions for grid development**. More specifically, we even observe that the combination of generation expansion and a 10% increase of exchange capacities brings Status Quo and Zone Shuffle to similar levels of average price spreads and interconnection between countries in 2040. **In the long run, the accurate coordination of generation and grid development is therefore as efficient as zone revision regarding this aspect**.

However, the two considered configurations are strongly distinguished by their impact on generation and interconnection dynamics. In fact, **2030 and 2040 results for the Big Country Split configuration illustrate a consistent trend with more RES curtailment and a less efficient use of cross-zonal capacities**. This proves **detrimental to both the penetration of fossil energy sources and the carbon in-**

**tensity of power generation.** In particular, the integration of generation expansion dynamics leads to significantly more installed capacity for fossil generation, which results in way higher shares of energy curtailed. While our approach does not integrate risk management aspects, we observe that **a significant increase of the number of zones seems to align investment signals with specific dispatch conditions where large amounts of fossil generation become valuable, even if it means relatively more curtailment and thermal penetration the rest of the time.**

On the other hand, the Zone Shuffle configuration seems to secure **limited impacts on renewable generation** while consistently favoring a **more efficient use of interconnections and higher level of interconnection between countries.** Observed variations with the status quo are nonetheless more limited at a Pan-European level. This is reminiscent of our Chapter 4 observation that a zone shuffle reconfiguration allows more limited redispatching gains than a reconfiguration that significantly increases the number of zones.

We can therefore identify two separate degrees of bidding zone revision. **Up to a certain point, zone revision can bring targeted benefits regarding system operation,** which nonetheless remain **limited on a Pan-European perspective. Beyond that point, it becomes a fundamental revision of the present “copper-plate” situation where market participants can contract transactions on large geographical areas without limits of volume, under operating conditions secured by marginal corrective actions of the TSOs.**

However, both zone reconfiguration are shown to strongly affect price volatilities and the overall correlation of prices in the system, with no particular consistency between the 2025, 2030 and 2040 trends. As previously developed, this suggests that **zone revision significant impacts liquidity and risk management, especially regarding forward market operations.**

In general, while specific zone amendment may be operationally relevant at local and Pan-European scale, bidding zone revision raises significant concerns involving strong redistributive effects, a significant

impact on price formation, and ultimately additional operational constraints on fossil generation and potentially less efficient investment signals. As anticipated in the international overview of Chapter 1, **it does not dismiss the need for physical system development, and in particular grid reinforcement, which appears as a “no-regret” measure for lowering system costs while relieving operational constraints on fossil generation.**

## GENERAL CONCLUSION AND PERSPECTIVES

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### OVERVIEW

As worldwide economies set ambitious targets to reduce greenhouse gas emissions, electric industries are facing profound transformations at international scale. In the world's large scale power systems, this is notably characterized by a **quick and spatially heterogeneous development of fatal renewable energy sources**, which often proves difficult to articulate with the inertia of transmission system development.

As the European power system stands out with a **zonal market design deployed on an unprecedented scale**, supranational policymakers are promoting an **increased economic cooperation between member states**, notably targeting grid constraints that may limit cross-zonal trade.

The work presented in this thesis analyzes **the possibility of an evolution of bidding zones for wholesale electricity markets in Europe**, which is often presented as a means to enhance market coupling by highlighting structural grid constraints into market operations.

Our approach both justifies and illustrates **the necessity for a multidimensional and multi-horizon analysis of this topic**. Our review of the academic literature shows how congestion management is increasingly considered **in relation to both market design and emerging types of energy resources**. We also conduct an overview of major power systems in the world and a chronology of institutional bidding zone revision efforts. We show how **system operation and market dynamics can be envisaged as embedded in long-term system trajectories**, and we illustrate the **main obstacles to the elaboration of a Pan-European approach to bidding zone revision**.

Above all, this work is structured around an extensive computational effort that combines **detailed modelling of grid constraints, zonal market dispatch and investment dynamics on short to long-term**

**scenarios.** This is complemented by the identification of **relevant techno-economic indicators** that are computed on **both an original 30-bus benchmark system and a large-scale static grid model of the European power system.**

We first concentrate on the **automated design of alternative zone configurations.** Optimal power flow simulations with DC approximation are conducted on both our benchmark system and representative 2025 dispatch scenarios for the European power system, providing series of locational marginal prices (LMPs). **Sets of candidate zone configurations are therefore created using conventional LMP-based clustering methods, with diversified numbers of zones** and an overall approach that **reconciles gains in redispatching actions and the relative preservation of status quo market dynamics.**

The candidate zone delineations are then evaluated according to indicators that combine congestion management and market dynamics on multiple horizons. In particular, **we approximate zonal dispatches based on nodal dispatch results to analyze nine alternative configurations for European bidding zones,** that are representative of three reconfiguration trends and three clustering approaches. We then articulate these configurations with representative sets of 2025, 2030 and 2040 dispatch scenarios. This step allows us to quantify **structural trade-offs between short-term redispatching benefits and medium- to long term market dynamics.** In particular, we show that while **redispatching reductions are not robust to system evolutions,** alternative zone reconfigurations tend to significantly **alter the stability of price signals** in the medium to long run, and to **induce strong redistributive effects** that dramatically increase system costs for consumers.

These observations lead us to **specifically focus on two candidate delineations** in the last step of our work: a configuration that equally balances zone splittings and mergers, called **Zone Shuffle**, and a configuration featuring splittings of the biggest bidding zones, called **Big Country Split.** We design three reduced models that correspond to the status quo and our two alternative zone configurations, then

introduce a **complementary simulation chain that combines generation expansion planning and unit commitment**. We complement our base case through a **sensitivity analysis** to alternative system trajectories, integrating both **generation investment dynamics and the expansion of cross-zonal exchange capacities**. This last steps confirms previously established concerns regarding price stability and redistributive effects, but we also show that a configuration involving significantly more bidding zones can be **detrimental to the large-scale penetration of fatal generation**, to general **interconnection dynamics** and to the **efficiency of generation investment signals**.

Our main contributions and findings are summarized in the sections below.

## MAIN CONTRIBUTIONS

### State-of-the-art.

Our recurrent literature review efforts throughout this thesis have been the occasion of original state-of-the-art contributions. Let us notably mention our **international overview of the market design and physical characteristics of major power systems** (Chapter 1), our **chronology of institutional bidding zone review efforts** to date (Chapter 1), and our review of **publicly available model and data for Pan-European DC-OPF simulations** (Chapter 2).

### Benchmark Model.

We designed a **30-bus benchmark static grid model** (Chapter 2) that is suitable for congestion-based network reduction test cases with high renewable penetration with European grid standards.

### Network Reduction.

We continued the PhD work of Nuno Marinho (Marinho, 2018) involving **the use of K-Means and Hierarchical LMP-based clustering for network reduction**. We notably introduced a zone

weight indicator and spatial constraints (in the form of geographical coordinates and bus adjacency matrices) in order to adapt these conventional clustering methods to the **automated bidding zone delineation problem**. We notably showed the interest of a **model-specific preliminary adaptation of clustering approaches** (Chapter 3) to create zone delineations that are relevant both for congestion management and the preservation of market dynamics. In Chapter 5, we also performed **original network reductions** based on previously computed line flows.

#### Simulation Chain and Evaluation Grid.

In line with our ambition for a multidimensional and multi-horizon analysis, we designed an **ad hoc simulation chain that combines DC optimal power flow simulations, capacity expansion planning and unit commitment** (Chapters 2 to 5). While partly relying on existing simulation softwares and scripts, we also **developed original tools**, especially regarding bus clustering, estimation of zonal dispatches and network reduction. This is complemented with the **gradual introduction of techno-economic indicators that involve both system operation and market dynamics**, culminating in the summary table at the end of Chapter 5.

## MAIN FINDINGS

#### Congestion Management.

Based on both our benchmark and our Pan-European case study, we showed that **while zone revision allows significant decreases of redispatching need with the number of zones, these operational benefits are not robust to medium- to long-term evolutions of the power system** (Chapter 4). Large-scale European simulations for 2030 and 2040 returned no significant redispatching reductions related to alternative configurations obtained with 2025 dispatch scenarios.

### Price Formation.

We showed that **the considered bidding zone revisions significantly affect price formation**, which we apprehended through zonal price volatility (Chapter 4 and 5), price vulnerability to generation outages (Chapter 4), cross-border price spreads (Chapter 5) and overall price correlation between zones (Chapter 5). These disruptions have been observed for all considered zone revisions, except outage vulnerability that is only affected in case of an increase of the number of zones. The observed trends are furthermore **not robust between the 2025, 2030 and 2040 horizons**. While this work does not include an explicit analysis of risk management regarding investment decisions, **we discussed the significant impact of these indicators on the efficiency of risk hedging and general conditions of market efficiency**.

### Redistributive Effects.

Based on our large-scale European case studies of Chapters 4 and 5, we showed that **zone revision creates a structural increase of the costs perceived by consumers**, due to an increase of production margins and net congestion rents. We also show that **only a small share of this increase is captured as net congestion rents by TSOs as an incentive for grid reinforcement**. In particular, massive investments in fatal generation capacities tend to significantly reduce the share of net congestion revenue perceived by TSOs in the medium to long run, due to additional congestion management costs (Chapter 5).

### Generation Dynamics and Investment Signals.

In Chapter 5, we illustrated how **a significant increase in the number of zones can create constrained market dynamics that are detrimental to the penetration of variable generation**. This may result in a relative increase of greenhouse gas emissions compared to the status quo trajectory in the medium to long run. By considering

investment dynamics, we also showed that this type of configuration can lead to **less efficient investment signals in the form of an overinvestment**. In fact, configurations with smaller zones tend to **cause an inaccuracy of market coupling constraints that is responsible for more RES curtailment**, to the point that market opportunities are more limited for variable renewable energy sources. **In practice, intensive reinforcement of transmission infrastructures in geographical areas with high RES concentration therefore appears as a no-regret measure in order to secure significant market opportunities for low-carbon resources.**

#### Interconnection Dynamics and Grid Development.

We illustrated in Chapter 5 that **limited amendments of the zone configuration can be beneficial regarding the use of cross-zonal capacities and the economic cooperation between countries**. We also showed that **a significant increase of the number of zones** can induce a **relatively lower use of interconnection capacities** and bring **no significant benefit regarding cross-country cooperation**. In addition, we showed in Chapter 5 that our multidimensional analysis is generally robust to homogeneous variations of cross-zonal capacities, which suggests that **none of the considered zone configurations creates structurally more efficient conditions for grid reinforcement**. Moreover, zone revision seems to consistently raise **medium to long-term concerns regarding redistributive effects price signals and transition costs** – which were not addressed in this work – with **limited benefits at a Pan-European scale**. In contrast, this work therefore highlights the value of **grid reinforcement**, which appears as a **“no-regret” measure to lower system costs and favor the penetration of fatal generation**.

## PERSPECTIVES

We identify four main avenues regarding the extension of this work to future contributions.

## Model Improvements

Further development of our modelling efforts could feature **more exhaustive representations of the European power system**, which in our case would include a **more detailed representation of peripheric bidding zones, realistic modelling of hydro and storage facilities, and the introduction of new types of energy resources** (e.g. flexibility resources and power electronics). These improvements should be made easier in the future by **the current development of open-source grid models** like the PyPSA-eur initiative (Hörsch *et al.*, 2018) and the **gradual integration of new network elements in future institutional works**, as can be anticipated from ENTSO-E's Vision 2030 (ENTSO-E, 2019c).

## Network Reduction

As explored in Chapter 3, many academic contributions are available regarding the **elaboration of more sophisticated grid partition methods**, whether they involve conventional clustering or more advanced graph theory. Above all, our objective in this work was to **illustrate the multidimensional impacts of congestion-based zone revision in general**, which did not justify the same efforts. Nonetheless, our analysis could be complemented with **more extensive network reduction efforts regarding cross-zonal exchanges**, notably with more reduced time granularity of cross-zonal capacities and the possible use of equivalent flow-based domains.

## Complementary Approaches to Zone Revision

In this work, we focused on the generation of **Pan-European zone revision scenarios**, and we targeted new zones that represent **large portions of existing bidding zones**, which is coherent with other existing academic and institutional works. Nonetheless, two examples from institutional publications show that this approach is not exhaustive of the possible forms of bidding zone revisions. First, the methodology proposed by ACER for the current Bidding Zone Reviews

is **way more restrictive of the possible zone revision patterns**. In particular, the methodology only allows zone splittings, based on clustering methods that are applied separately to each Member State (ACER, 2020a). Second, ENTSO-E and European policymakers have recently been discussing **the formation of offshore bidding zones concentrating large offshore wind generation capacities** (ENTSO-E, 2020b). This last example notably questions the economic efficiency of a bidding zone with no domestic demand and a frequent occurrence of low or negative spot prices. **The methodologies and indicators developed in this thesis could nonetheless be easily adapted both to country-specific zone revision and the evaluation of offshore bidding zones.**

#### Complementary Approaches to Market and Investment Dynamics

In this work, **we mostly approached market and investment dynamics through unit commitment constraints and investment decisions with perfect foresight and no risk management**. Complementary approaches could nonetheless be developed in further works to address **more realistic bidding dynamics and investment decisions**. Let us notably mention the use of agent-based market modelling including strategic behaviors from market participants (Fraunholz, Keles and Fichtner, 2019), forward market simulation (Bevin-McCrimmon *et al.*, 2018) or the analysis and extrapolation of spot and forward market data (DNV GL Energy, 2020). On the other hand, and in closer relation to the methodologies developed in this work, **further approaches could integrate grid investment decisions in the form of transmission expansion planning frameworks**. This type of approaches is regularly featured in works addressing the coordination of grid and generation development, in particular regarding grid architectures for the connection of offshore resources (Gea-Bermúdez *et al.*, 2020).

## LIST OF PUBLICATIONS

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### CONFERENCE PAPERS

- T. Brouhard, M. Hennebel, M. Petit and C. Gisbert, "Bidding Zones of the European Power System: Benefits of a Multi-Dimensional Approach to the Evaluation of Possible Delineations," *2020 17th International Conference on the European Energy Market (EEM)*, Stockholm, Sweden, 2020, pp. 1-6. doi: 10.1109/EEM49802.2020.9221998
- T. Brouhard, M. Hennebel, M. Petit and C. Gisbert, "Characterization of Bidding Zone Robustness under Medium and Long-Term System Evolution Scenarios," *2021 IEEE Madrid PowerTech*, Madrid, Spain, 2021, pp. 1-6. doi: 10.1109/PowerTech46648.2021.9494992
- T. Brouhard, M. Hennebel, M. Petit and C. Gisbert, "Identifying the Determinants of Efficient System Operation Through an International Review of Wholesale Electricity Markets." *2022 18th International Conference on the European Energy Market (EEM)*, Ljubljana, Slovenia, 2022, pp. 1-6. doi: 10.1109/EEM54602.2022.9921117

### PEER-REVIEWED JOURNALS

- **[To be published]** T. Brouhard, M. Hennebel, M. Petit and C. Gisbert, "A Clustering Approach to the Definition of Robust, Operational and Market Efficient Delineations for European Bidding Zones"



## APPENDICES

### A. GRID MODEL FOR THE 30-BUS BENCHMARK SYSTEM.

Table A-1: Bus Characteristics.

Name	Status Quo Zone	Voltage Level [kV]	Longitude	Latitude	Demande Keys	
					Reference	Long-Term "High-Demand" Scenario
N1	1	400	2.00	43.00	2.9%	3.0%
N2	1	400	3.75	42.00	2.9%	3.0%
N3	1	400	5.50	43.00	2.9%	3.0%
N4	1	400	2.75	44.50	2.9%	3.0%
N5	1	400	4.75	44.50	2.9%	3.0%
N6	1	400	6.00	46.00	2.9%	3.0%
N7	1	400	7.50	43.50	2.9%	3.0%
N8	1	400	9.50	43.50	2.9%	3.0%
N9	1	400	8.25	45.00	2.9%	3.0%
N10	1	400	10.50	46.00	2.9%	3.0%
N11	3	400	12.00	43.00	3.6%	3.3%
N12	3	400	14.50	42.00	3.6%	3.3%
N13	3	400	16.00	43.50	3.6%	3.3%
N14	3	400	12.50	45.25	3.6%	3.3%
N15	3	400	14.50	45.50	3.6%	3.3%
N16	2	400	7.00	47.00	4.8%	4.8%
N17	2	400	7.50	49.50	4.8%	4.8%
N18	2	400	8.75	50.50	4.8%	4.8%
N19	2	400	9.25	47.00	4.8%	4.8%
N20	2	400	10.00	49.75	4.8%	4.8%
N21	3	400	11.50	47.75	3.6%	3.3%
N22	3	400	15.75	48.00	3.6%	3.3%
N23	3	400	12.50	49.50	3.6%	3.3%
N24	3	400	14.75	50.00	3.6%	3.3%
N25	3	400	13.50	47.25	3.6%	3.3%
N26	4	400	10.00	52.00	2.2%	2.6%
N27	4	400	12.00	51.50	2.2%	2.6%
N28	4	400	14.00	52.00	2.2%	2.6%
N29	4	400	11.75	53.00	2.2%	2.6%
N30	4	400	13.25	54.00	2.2%	2.6%

Table A-2: Generation Cost Assumptions.

Fuel Type	Variable Generation Cost [€/MWh]
Nuclear	9
Hard Coal	20
Gas	45
Hydro Reservoir	55
RES	0

Table A-3: Generator Data.

Name	Node Name	Fuel Type	Pmax [MW]	
			Reference	Long-Term "High RES" Scenario
N1_prod	N1	Onshore Wind	3000	7000
N2_prod	N2	PV	6000	12000
N3_prod	N3	Gas	8000	4000
N4_prod	N4	Offshore Wind	5000	10000
N5_prod	N5	Onshore Wind	3000	7000
N6_prod	N6	Onshore Wind	3000	6000
N7_prod	N7	Onshore Wind	4000	8000
N8_prod	N8	PV	6000	12000
N9_prod	N9	Nuclear	7000	3500
N10_prod	N10	Gas	5000	2500
N11_prod	N11	PV	7000	14000
N12_prod	N12	Onshore Wind	5000	10000
N13_prod	N13	Gas	8000	4000
N14_prod	N14	Hydro Reservoir	9000	9000
N15_prod	N15	Hydro RoR	1000	1000
N16_prod	N16	Gas	8000	4000
N17_prod	N17	Onshore Wind	4000	8000
N18_prod	N18	Offshore Wind	6000	12000
N19_prod	N19	Gas	8000	4000
N20_prod	N20	Hard Coal	4000	2000
N21_prod	N21	Onshore Wind	3000	7000
N22_prod	N22	Onshore Wind	3000	6000
N23_prod	N23	Hard Coal	3000	1500
N24_prod	N24	Offshore Wind	6000	12000
N25_prod	N25	Nuclear	5000	2500
N26_prod	N26	Offshore Wind	6000	12000
N27_prod	N27	Nuclear	4000	2000
N28_prod	N28	Hydro RoR	500	500
N29_prod	N29	Hydro Reservoir	2500	2500
N30_prod	N30	Offshore Wind	7000	14000

Table A-4: Line Characteristics.

Name	Node Code 1	Node Code 2	Reactance [Ohm/km]	Thermal Transmission Limit [MVA]		
				Reference	Medium-Term Reinforcement Scenario	Long-Term Addition Scenario
N1N2line	N1	N2	10	1500	1500	1500
N1N4line	N1	N4	10	1500	1500	1500
N2N3line	N2	N3	10	1500	1500	1500
N3N4line	N3	N4	10	1500	1500	1500
N3N5line	N3	N5	10	1500	1500	1500
N3N7line	N3	N7	10	1500	1500	1500
N4N5line	N4	N5	10	1500	1500	1500
N5N6line	N5	N6	10	1500	2000	2000
N6N7line	N6	N7	10	1500	1500	1500
N6N9line	N6	N9	10	1500	1500	1500
N6N16line	N6	N16	10	1500	2000	2000
N7N8line	N7	N8	10	1500	1500	1500
N7N9line	N7	N9	10	1500	1500	1500
N8N9line	N8	N9	10	1500	1500	1500
N8N10line	N8	N10	10	1500	1500	1500
N8N11line	N8	N11	10	1500	1500	1500
N9N10line	N9	N10	10	1500	1500	1500
N9N16line	N9	N16	10	1500	1500	1500
N9N19line	N9	N19	10	1500	2000	2000
N10N14line	N10	N14	10	1500	1500	1500
N10N19line	N10	N19	10	1500	1500	1500
N11N12line	N11	N12	10	1500	1500	1500
N11N13line	N11	N13	10	1500	1500	1500
N11N14line	N11	N14	10	1500	1500	1500
N12N13line	N12	N13	10	1500	1500	1500
N13N14line	N13	N14	10	1500	1500	1500
N13N15line	N13	N15	10	1500	1500	1500
N14N15line	N14	N15	10	1500	1500	1500
N14N21line	N14	N21	10	1500	2000	2000
N15N25line	N15	N25	10	1500	2000	2000
N16N17line	N16	N17	10	1500	1500	1500
N16N19line	N16	N19	10	1500	1500	1500
N16N18line	N16	N18	10	1500	1500	1500
N17N18line	N17	N18	10	1500	1500	1500
N18N20line	N18	N20	10	1500	1500	1500
N18N26line	N18	N26	10	1500	2000	2000
N19N20line	N19	N20	10	1500	1500	1500
N19N21line	N19	N21	10	1500	2000	2000
N20N21line	N20	N21	10	1500	1500	1500
N20N23line	N20	N23	10	1500	1500	1500
N20N26line	N20	N26	10	1500	1500	1500
N20N27line	N20	N27	10	1500	1500	1500
N21N23line	N21	N23	10	1500	1500	1500
N21N25line	N21	N25	10	1500	1500	1500
N22N24line	N22	N24	10	1500	1500	1500
N22N25line	N22	N25	10	1500	1500	1500
N23N24line	N23	N24	10	1500	1500	1500
N23N25line	N23	N25	10	1500	1500	1500

<b>N23N27line</b>	N23	N27	10	1500	1500	1500
<b>N24N25line</b>	N24	N25	10	1500	1500	1500
<b>N24N28line</b>	N24	N28	10	1500	1500	1500
<b>N26N27line</b>	N26	N27	10	1500	1500	1500
<b>N26N29line</b>	N26	N29	10	1500	1500	1500
<b>N27N28line</b>	N27	N28	10	1500	1500	1500
<b>N27N30line</b>	N27	N30	10	1500	1500	1500
<b>N27N29line</b>	N27	N29	10	1500	1500	1500
<b>N28N30line</b>	N28	N30	10	1500	1500	1500
<b>N29N30line</b>	N29	N30	10	1500	1500	1500
<b>N3N6line</b>	N3	N6	10	-	-	1500
<b>N8N14line</b>	N8	N14	10	-	-	1500
<b>N18N19line</b>	N18	N19	10	-	-	1500
<b>N23N26line</b>	N23	N26	10	-	-	1500

## B. RESUME EN FRANÇAIS

En Europe, les marchés de gros de l'électricité suivent un **système en tarification zonale**. Le tracé des zones de prix correspondantes se confond largement avec les frontières politiques entre pays.



Figure B-1: Configuration zonale actuelle en Europe.

Au sein d'une même zone, les acteurs de marché sont libres de réaliser des transactions sans contraintes de volume, d'où l'image d'un fonctionnement en plaques de cuivre. Les échanges commerciaux entre zones sont toutefois soumis à des **capacités d'échange** établies en temps réel par les gestionnaires de réseau de transport.

Dans le contexte d'une intégration rapide de sources d'énergie renouvelable intermittentes sur des points très localisés du réseau de transport d'électricité, l'objectif d'assurer des conditions d'exploitation efficaces du système électrique sur le long-terme devient une condition nécessaire à la décarbonation du mix énergétique.

Dans la dernière décennie, plusieurs législations européennes ont ainsi entériné une volonté d'aligner l'organisation des marchés de gros sur ces objectifs de long-terme tout en favorisant la coopération économique entre états membres. Le code de réseau « Capacity Allocation – Congestion Management » (European Commission, 2015) (European Commission, 2015) et le paquet « Clean Energy for all Europeans » (European Commission, 2019) incitent notamment les gestionnaires de réseau à ouvrir le maximum des capacités physiques disponibles aux échanges commerciaux.

Alors que certains gestionnaires de réseau européens sont confrontés à des coûts très élevés de gestion des congestions, la possibilité d'une révision des zones de prix des marchés de gros du système électrique est ainsi mise en avant comme un moyen de faire apparaître les contraintes structurelles du réseau dans le fonctionnement des marchés zonaux.

Cette thèse propose un travail de modélisation et d'analyse technico-économiques d'une évolution des zones de prix des marchés de gros du système électrique européen. En particulier, elle s'appuie des méthodes de modélisation et des indicateurs qui portent à la fois sur **les conditions d'exploitation du système électrique** et **les dynamiques des marchés de gros**, en s'attachant à étudier les impacts **du court au long terme**.

Dans ce résumé en français, nous proposons une revue générale de la méthodologie développée dans cette thèse, avant de présenter ces contributions sur les trois points suivants : la **conception automatisée de découpages zonaux alternatifs**, **l'évaluation multi-horizon et pluridimensionnelle des configurations obtenues**, et une **analyse de la sensibilité de long terme des trajectoires du système** – qui intègre le développement des réseaux de transport et les dynamiques d'investissement dans le parc de production.

## B.1 Méthodologie Générale

Ce travail combine des questions d'exploitation du système électrique et de fonctionnement des marchés de gros selon une perspective du court au long-terme. Cette ambition se traduit donc par une complémentarité des méthodes et indicateurs employés, avec trois contributions principales :

- 1) Le découpage automatisé de configurations zonales alternatives s'appuie sur des **simulations d'Optimal Power Flow avec approximation en courant continu (DC-OPF)**. Elles permettent d'obtenir un dispatch nodal détaillé en optimisant le coût marginal de production, et débouchent sur des séries de **prix nodaux ou locational marginal prices**. Ces dernières servent ensuite de critère pour associer automatiquement les

nœuds du modèle via des **algorithmes de clustering**. Le logiciel PowerFactory développé par Digsilent (DigSilent GmbH, 2020) a été utilisé pour les simulations DC-OPF, tandis que les algorithmes de clustering ont été implémentés en Python.

- 2) L'analyse des configurations zonales obtenues est réalisée en **extrapolant les dispatchs zonaux à partir des dispatchs nodaux obtenus en sortie des simulations DC-OPF**. Cette étape s'appuie sur l'hypothèse que, pour une même situation d'équilibre offre-demande, la position nette de chaque zone est identique entre les dispatchs nodaux et zonaux. Cette hypothèse permet de considérer indépendamment chaque problème de dispatch zonal et de déduire la production de chaque générateur par simple *merit order*.
- 3) L'analyse de trajectoires long-terme pour le système électrique s'appuie sur **une étape de réduction du modèle de réseau utilisé dans les étapes précédentes**. Celle-ci consiste notamment à agréger le parc de production et les demandes de chaque zone sur un nœud unique tout en définissant des **capacités d'échanges représentatives** entre ces clusters. Cette étape fait ensuite intervenir un outil qui exécute successivement trois modules : une **sélection automatisés de jours représentatifs** pour chaque année étudiée, un module de **Capacity Expansion Planning (CEP)** qui optimise le coût total de production en intégrant des options d'investissement pour certaines années cible, et un module de **Unit Commitment (UC)** qui permet de simuler l'équilibre offre-demande sur l'ensemble de la période étudiée. Cette partie s'appuie sur une chaîne d'outils existante et présentée dans (Lebeau *et al.*, 2021)

L'articulation de ces étapes de modélisation est représentée sur la figure B-2

Les simulations présentées dans ce travail portent sur deux études de cas principales. D'une part, une grande partie des méthodes et indicateurs employés ont **été testés sur un modèle original figurant un réseau théorique à trente nœuds**. Celui-ci a été conçu pour être représentatif de situations de congestions rencontrées dans le système électrique européen, en utilisant notamment des données publiques du projet E-Highway 2050 (e-HIGHWAY 2050, 2014). Une description

du modèle à 30 nœuds est disponible dans l'annexe précédente.

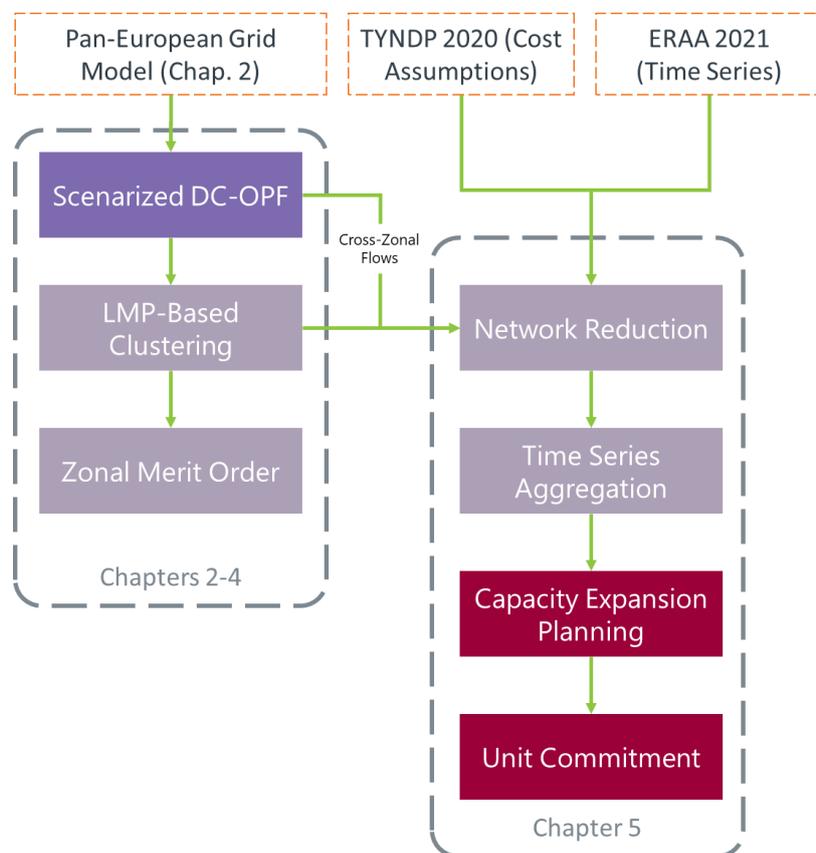


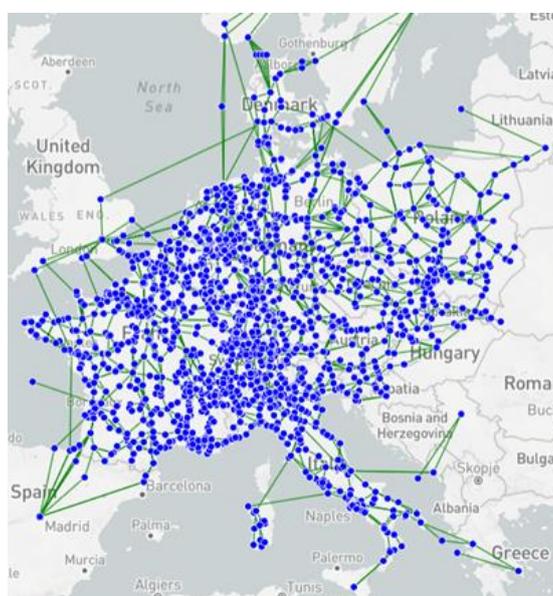
Figure B-2: Chaîne de simulation complète.

D'autre part, ce travail s'appuie sur **un modèle de réseau représentant une grande partie du système électrique européen**. Celui-ci a été construit en interne au département SYSTEME d'EDF R&D sur la base de données publiques. Il reprend notamment la structure de réseau publiée par l'UCTE en 2008 (UCTE, 2008) et a été régulièrement **mis à jour pour s'aligner sur le scénario « National Trends » du TYNDP 2020 de l'ENTSO-E** (ENTSO-E, 2020d).

Le modèle européen intègre environ 3000 nœuds, 4000 lignes et 4500 unités de génération. Il comporte une description détaillée de douze zones de marché d'Europe Continentale : l'Allemagne (DE), l'Autriche (AT), la Belgique (BE), l'ouest du Danemark (DE1), la France (FR), l'Italie (IT), les Pays-Bas (NL), la Pologne (PL), la Slovaquie (SK), la Slovénie

(SL), la Suisse (CH), et la République Tchèque (CZ). Onze régions plus périphériques sont représentées de manière simplifiée par au plus quelques nœuds : la Croatie (HR), l'est du Danemark (DE2), la Péninsule Ibérique (ES+PT), la Grande-Bretagne (GB), la Grèce (GR), la Hongrie (HU), la Lituanie (LT), la Norvège (NO), la Serbie (RS), la Suède (SE), l'Ukraine (UA).

L'utilisation de ce modèle limite donc notre analyse à des reconfigurations des zones de prix d'Europe continentale, mais permet toutefois de quantifier leur impact à une maille plus large. Une représentation géographique du modèle est disponible en figure B-3.



*Figure B-3: Représentation géographique du modèle de réseau européen.*

Les simulations DC-OPF et les analyses de dispatch zonal qui en découlent s'appuient sur 600 scénarios de dispatch représentatifs des années 2025, 2030 et 2040. Ceux-ci ont été obtenus sur la base de deux scénarios de répartition nodale de la demande fournis dans les données du modèle de réseau TYNDP 2020. (ENTSO-E, 2020e), articulés avec 600 scénarios nationaux de facteurs de charge de sources renouvelables extraits de la plateforme renewable.ninja (Pfenninger and Staffell, 2016; Staffell and Pfenninger, 2016). Pour

chacun des trois horizons temporels, on retrouve ainsi 300 scénarios représentatifs d'une pointe été et 300 d'une pointe hiver, sélectionnés en appliquant un algorithme K-Means sur des données horaires historiques 1985-2016.

Les simulations de *Capacity Expansion Planning* et *Unit Commitment* portant sur des modèles réduits du système électrique font intervenir des séries temporelles de demande et de production renouvelables extraites de l'exercice ERAA 2021 de l'ENTSO-E (ENTSO-E, 2021c). Une étape de réduction reposant également sur l'algorithme K-Means permet d'isoler 50 jours représentatifs sur chaque année de la période 2025 – 2040, soit 1200 intervalles de marché par an.

## B.2 Découpage automatisé de configurations zonales alternatives.

Dans la littérature académique, l'approche la plus populaire pour le découpage automatisé des zones de prix repose **sur l'application d'algorithmes de clustering à des séries de prix nodaux** obtenus pour différents scénarios d'équilibre offre-demande.

Dans le cadre d'une révision des zones de marché européennes, nous avons choisi de mettre également en avant des **contraintes spatiales qui permettent de rendre les configurations zonales obtenues plus lisibles**, avec des scissions et des fusions de zones clairement identifiables par rapport à la configuration zonale actuelle. Nous avons donc choisi d'adapter **deux algorithmes de clustering traditionnels que sont les partitionnements K-Means et Hiérarchiques** selon trois modalités :

- **Une méthode K-Means reposant sur la pondération des prix nodaux et des coordonnées géographiques** des nœuds en input, notée (w-K).
- **Une méthode Hiérarchique reposant sur la pondération des prix nodaux et des coordonnées géographiques** des nœuds en input, notée (w-H).
- **Une variante de la méthode Hiérarchique pondérée** qui intègre aussi une **matrice de connexité** des nœuds sur le réseau, notée (c-wH).

Il a donc été nécessaire d'établir une pondération des prix nodaux ( $w_{LMP}$ ) et des coordonnées géographiques ( $w_x$ ) qui permet de donner un maximum de poids aux coordonnées géographiques sans toutefois dégrader les performances du clustering par prix nodaux, censé promouvoir l'alignement du tracé des zones avec les congestions les plus significatives sur le réseau. Nous introduisons pour cela **un indicateur d'effort de redispatching**, qui mesure la part d'électricité redispatchée entre les dispatchs zonaux initiaux et les dispatchs nodaux finaux. La figure B-4 montre la valeur moyenne de RE sur les 600 scénarios d'équilibre offre-demande 2025, pour des configurations zonales obtenues avec un nombre de zones identique à la configuration statu quo, avec les trois méthodes de clustering et pour différentes pondérations des prix nodaux.

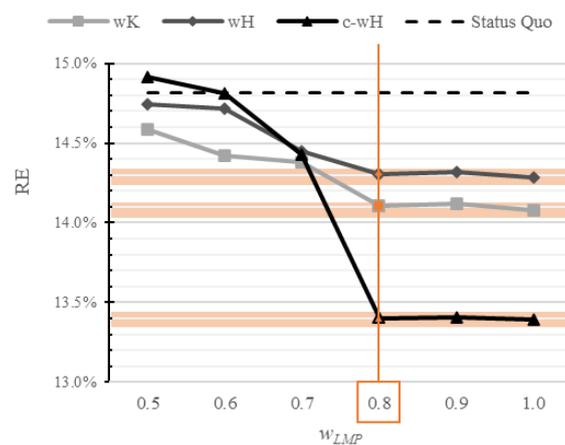


Figure B-4: Pondération des prix nodaux et des coordonnées géographiques en préparation des travaux de clustering.

Pour le modèle de réseau et les scénarios considérés, il semble que le choix d'une pondération respective de 0.8 et 0.2 pour les prix nodaux et les coordonnées géographiques des nœuds permette le meilleur compromis. Ce paramétrage a ainsi été utilisé pour générer des configurations zonales alternatives à tester dans la suite de ce travail.

**Neuf configurations zonales candidates** sont ainsi proposées à l'étude, issues des trois méthodes de clustering retenues et déclinées selon **trois tendances de reconfiguration** régulièrement envisagées

dans la littérature et dans des publications institutionnelles. Pour chaque algorithme de clustering, trois configurations alternatives ont ainsi été générées comme suit :

- « **Zone Shuffle** » : le nombre de zones dans le système reste inchangé, mais on retient les fusions et scissions privilégiées par l'algorithme.
- « **Big Country Split** » : on augmente progressivement le nombre de zones demandé jusqu'à obtenir une scission des quatre plus grosses zones du modèle (Allemagne, France, Italie, Pologne) en au moins deux zones.
- « **Regionalized System** » : « Big Country Split » : on augmente progressivement le nombre de zones demandé jusqu'à obtenir une scission des quatre plus grosses zones du modèle en au moins trois zones.

Une illustration de trois des neuf configurations retenues est présentée en figure B-5.

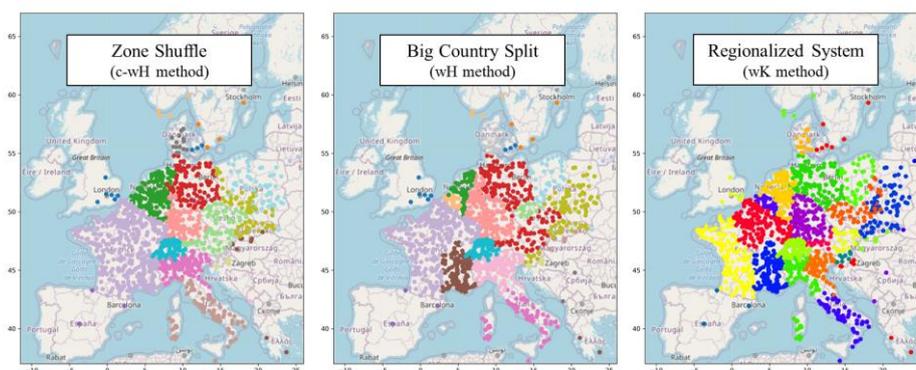


Figure B-5: Exemples de configurations zonales étudiées.

### B.3 Evaluation des configurations zonales obtenues

Les neuf configurations zonales candidates présentées dans la section précédente ont été évaluées selon trois volets de 600 scénarios d'équilibre offre-demande 2025, 2030 et 2040 et pour des indicateurs relevant des trois dimensions suivantes :

- **Exploitation du système** : utilisation de l'indicateur d'effort de redispatching RE ;
- **Effets distributifs entre acteurs** : analyse des mouvements de revenus et de coûts perçus par les consommateurs, les producteurs et les gestionnaires de réseau de transport à l'échelle du système ;
- **Formation des prix** : suivi des niveaux de volatilité des prix zonaux rencontrés dans le système, ainsi que de l'impact de la perte de certains générateurs stratégiques sur les prix.

Concernant l'exploitation du système et la gestion des congestions, nos résultats confirment le phénomène régulièrement observé dans la littérature : à court terme, l'augmentation du nombre de zones permet une réduction des besoins en redispatching, en rapprochant le système d'un fonctionnement en tarification nodale. Si la configuration zonale statu quo retourne un niveau moyen de 15% de redispatching sur l'année 2025, ce chiffre passe en-dessous de 10% pour les trois configurations « Regionalised System ».

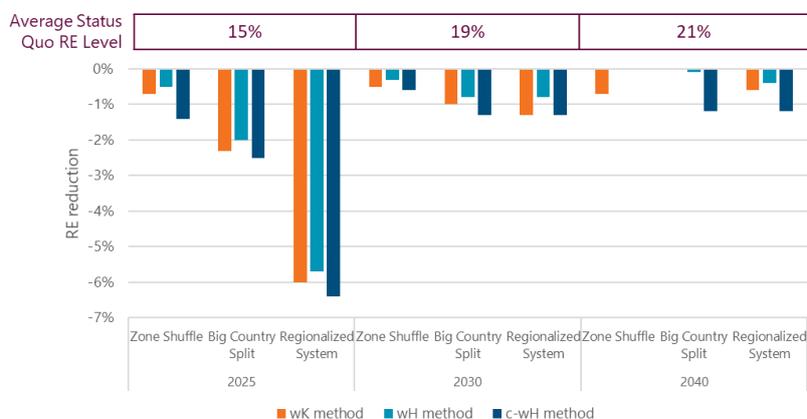


Figure B-6 : Impact des configurations zonales étudiées sur les efforts de redispatching.

Cependant, la figure B-6 montre que **pour des horizons 2030 et 2040, les configurations zonales envisagées ne conduisent à aucune réduction significative des besoins en redispatching**. Les bénéfices opérationnels de reconfigurations zonales pouvant paraître optimales à l'horizon 2025 ne sont donc pas robustes dans le temps, en lien avec l'évolution physique du système qui change la répartition

de la production et de la consommation – donc la distribution des congestions sur le réseau.

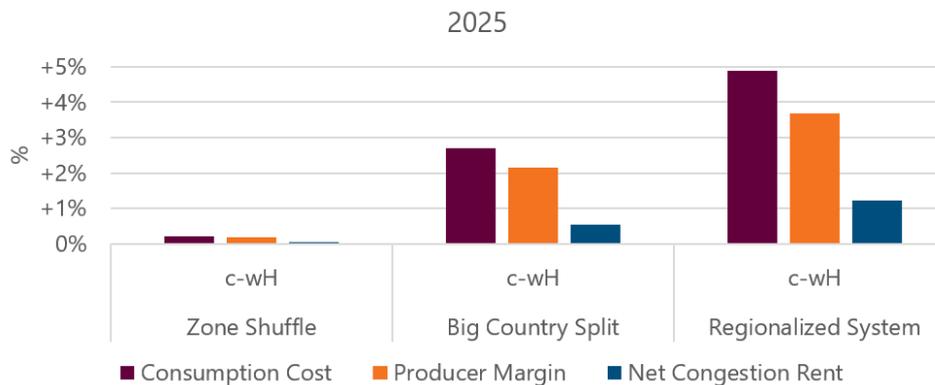
Sous un angle plus économique, nous montrons qu'une révision des bidding zones est susceptible, y compris à court-terme, de **déclencher des transferts économiques systématiques entre les principaux acteurs du système électrique**, en particulier les producteurs, consommateurs et gestionnaires de réseau de transport. Notre analyse porte en particulier sur trois grandeurs : le coût de consommation, qui correspond aux volumes de demandes valorisés aux différents prix zonaux, la marge cumulée des producteurs, ainsi que la rente nette de congestion perçue par les gestionnaires de réseau. En particulier, ce dernier revenu correspond au total des volumes échangés entre zones, valorisés par les écarts de prix zonaux, et auquel on retire le coût de gestion des congestions.

A l'échelle du système, on observe en particulier la relation suivante :

$$\text{Coût de Conso.} - \text{Marge Producteurs} - \text{Rente Nette de Cong.} = \text{Coût du Syst.} \quad (B.1)$$

Où le coût du système est invariant d'une configuration zonale à l'autre – et correspond au coût marginal de production après actions correctives liées aux congestions.

La figure B-7 montre notamment que les configurations comportant plus de zones (« *Big Country Split* » et « *Regionalized System* ») conduisent à des **augmentations significatives des coûts de consommation**, en grande partie liées à une augmentation des marges producteurs. Ces résultats suggèrent ainsi que **de telles reconfigurations zonales sont susceptibles de faire peser une pression économique importante au consommateur, sur laquelle les gestionnaires de réseau dégagent peu de rente nette de congestion** – qui est pourtant une incitation au renforcement réseau.



*Figure B-7: Variation des principaux indicateurs de coût et de revenu pour les scénarios de dispatch 2025 - relativement au coût de consommation observé dans la configuration statu quo.*

Ce phénomène est accentué dans les scénarios de dispatch 2030 et 2040.

Du point de vue de la formation des prix, le suivi des volatilités zonales et de la vulnérabilité des prix à la perte de générateurs stratégiques montre que l'augmentation du nombre de zones tend, à moyen et long-terme, à accentuer les valeurs extrêmes observées. En particulier, les valeurs à risque 10% associées à ces deux indicateurs ont tendance à augmenter significativement aux horizons 2030 et 2040, ce qui suggère que **les dynamiques de formation des prix peuvent être particulièrement affectées à long terme dans certaines zones du système**, ce qui suggère **des impacts forts sur la liquidité de marché et sur l'efficacité des pratiques de gestion de risques**.

#### B.4 Analyse de trajectoires long-terme pour le système électrique

Dans cette étape comportant une **représentation temporelle plus détaillée** et une approche plus dynamique des trajectoires d'évolution du système électrique, nous nous focalisons sur la comparaison de **trois scénarios de reconfiguration des zones de prix** : le **statu quo**, la **configuration « Zone Shuffle » obtenue avec la méthode (c-wH)**, et la **configuration « Big Country Split » obtenue avec la méthode (c-wH)**.

En particulier, les découpages obtenus avec cette méthode permettent

une réduction plus importante des besoins en redispatching en comparaison de leurs homologues obtenus avec les méthodes (wH) et (wK). Par ailleurs, ces configurations alternatives « *Zone Shuffle* » et « *Big Country Split* » illustrent **deux approches complémentaires de la révision des zones de prix européennes** : une **combinaison de fusions et de scissions à nombre de zones constant** pour la première, et **une accumulation de scissions** pour la seconde. Les configurations « *Regionalized System* » ont été écartées à ce stade, car elles traduisent plutôt une amplification de l'approche « *Big Country Split* » qu'une logique de révision zonale distincte.

Comme évoqué en section B.2, cette analyse repose sur des modèles réduits du système correspondants aux configurations zonales étudiées. Les hypothèses de production et de demande ont notamment été agrégées selon des clusters correspondant aux différentes zones étudiées. Des **capacités d'échange entre zones ont ensuite été établies sur la base des flux maximums observés dans les résultats des simulations d'*optimal power flow* précédentes.**

Des **options d'investissement dans les filières gaz, éolien onshore et offshore et photovoltaïque** ont ensuite été définies dans les zones comportant déjà des actifs de production correspondants, aux horizons 2030 et 2040, en s'alignant sur les hypothèses de coût proposées par le TYNDP 2020. Afin d'étudier la sensibilité des résultats obtenus à ces échéances, une **analyse de sensibilité sur les capacités d'échange a été réalisée**, en introduisant des variations homogènes de +10% et +30% sur toutes les frontières en 2030 et 2040.

Les nouvelles capacités de production déployées par le module de *Capacity Expansion Planning* à l'horizon 2040 sont présentées dans la figure B-8 avec une sensibilité aux variations de capacités d'échange. Si les volumes installés et l'arbitrage entre technologies dépend fortement des hypothèses de coût et de facteurs de charge renouvelables, deux observations générales se dégagent néanmoins :

- **L'augmentation des capacités d'échange a tendance à réduire les besoins en nouvelles capacités de production**, ce qui traduit un couplage plus fort entre zones ;
- **La configuration « *Big Country Split* », qui illustre la**

**généralisation de plus petites zones dans le système, conduit à des capacités installées plus importantes.**



*Figure B-8: Capacité de production additionnelle à l'horizon 2040 - Par rapport au scénario de référence, relativement à la capacité*

Ces observations sont complétées par une analyse détaillée qui intègre notamment la pénétration des sources renouvelables dans le mix énergétique Pan-Européen et le niveau d'utilisation des capacités d'échange. En particulier, on observe que **la mise en place de la configuration « Big Country Split » conduit à relativement plus d'écêtement et une utilisation plus limitée des interconnexions sur un horizon moyen à long-terme.**

Dans un contexte où les zones de prix sont généralement plus petites, où les transactions entre acteurs de marché sont contraintes par des frontières additionnelles, on observe ainsi **des dynamiques d'investissement moins efficaces** concernant les sources d'énergie renouvelables. **En particulier, ces nouvelles capacités sont valorisées dans des pics de consommation locaux qui ne coïncident pas nécessairement avec les opportunités d'échange entre zones.** Cette production est donc écôtée plus souvent en comparaison.

## B.5 Principales Conclusions

D'un point de vue méthodologique, les principales contributions de ce travail sont caractérisées par :

- **L'élaboration d'une série d'études de cas complémentaires**, avec à la fois un focus sur le système électrique à grande échelle et la **conception d'un modèle de test original à 30 nœuds** ;
- Le **prolongement de travaux précédents sur la réduction de réseau**, notamment l'adaptation de méthodes de clustering au découpage de zones de prix dans (Marinho, 2018) ;
- Le **développement d'une chaîne de simulation qui combine des approches réseau et marché sur plusieurs horizons temporels** ;
- La **consolidation progressive d'une grille d'évaluation pluridimensionnelle**.

Cette analyse permet également de dégager plusieurs enseignements généraux sur le sujet d'une révision des zones de prix du système électrique européen :

- **L'absence de robustesse des bénéfices obtenus à court terme sur la gestion des congestions** ;
- **Un point de vigilance sur les transferts économiques structurels entre acteurs du système**. Dans les configurations où le nombre de zones augmente, cela se traduit par une **pression économique sur les consommateurs qui apparaît comme disproportionnée au regard des revenus utiles au développement des infrastructures de transport d'électricité** ;
- La mise en évidence de **perturbations de la formation des prix**, qui pourrait conduire à des conditions moins efficaces de gestion des risques et de liquidité, en particulier sur les marchés forward ;
- L'idée d'un **compromis entre une révision relativement marginale des zones** – illustrée par les scénarios « *Zone Shuffle* » - et une **révision plus structurelle** conduisant à la formation de plus petites zones. Même si la première option semble apporter des bénéfices relativement limités à l'échelle

Pan-Européenne, la seconde voit son intérêt opérationnel à court terme largement remis en question par des perturbations des dynamiques de marché à moyen et long terme.

- Dans ce contexte, **l'option du renforcement réseau semble être une approche sans regret** pour valoriser les ressources intermittentes dans les zones où elles sont fortement concentrées, et ainsi articuler les **problématiques de couplage des marchés à court-terme** avec des **objectifs de décarbonation du système à long terme**.

Plusieurs prolongements de ce travail sont également envisageables pour des projets de recherche à venir :

- **L'enrichissement des modèles utilisés**, avec notamment la prise en compte plus détaillée de moyens de stockage et de flexibilité ;
- **Le renforcement de l'approche de réduction de modèle de réseau**, notamment par l'utilisation d'un formalisme *flow-based* pour les contraintes d'échange entre zones ;
- La considération de projets de **zones de prix spécifiques aux ressources offshore**, ou des **analyses spécifiques à certaines régions du système électrique** ;
- **Une analyse dédiée à la gestion des risques et à l'efficacité de marché**, qui pourrait notamment faire intervenir des données issues de marchés *forward* ou de la modélisation par agent.
- **Une approche reposant sur l'optimisation des décisions de renforcement du réseau** par un formalisme de *Transmission Expansion Planning*.



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**Titre :** Analyse et modélisation technico-économique d'une évolution des zones de prix des marchés de gros du système électrique européen.

**Mots clés :** Marchés de gros de l'électricité, Transport d'électricité, Clustering, Énergies Renouvelables.

**Résumé :** En Europe, les marchés de gros de l'électricité sont organisés selon un système zonal, avec des zones correspondant essentiellement aux frontières des états. Au sein de ces zones, les acteurs de marché sont libres de s'échanger de l'électricité sans contraintes de volume et à un prix unique. En revanche, les capacités d'échanges commerciaux entre ces zones sont limitées, à l'export comme à l'import, suivant des seuils représentatifs des contraintes physiques du réseau. Dans la lignée du Clean Energy Package et des codes de réseau introduits par la Commission Européenne, les gestionnaires de réseau de transport sont aujourd'hui incités à maximiser les capacités d'échange ouvertes aux échanges transfrontaliers, quitte à définir des plans d'action à court-terme pour réduire les contraintes réseau.

En cas de persistance de congestions structurelles, de nouveaux découpages des zones de marché seront envisagés, ce qui a déjà donné lieu à plusieurs analyses de la part des régulateurs et des gestionnaires de réseau. De telles reconfigurations auraient un impact déterminant sur l'activité des énergéticiens européens, dont les politiques d'exploitation et d'investissement dans les actifs de production dépendent du design de marché. L'objectif de cette thèse est donc de proposer une modélisation et une analyse technico-économique de différentes reconfigurations des zones de prix des marchés de gros du système électrique européen, afin d'en décrire l'impact sur l'exploitation des parcs de production d'électricité, la gestion et le coût du système pour la collectivité, la formation des prix et la coordination des investissements dans le réseau et la production.

**Title :** Techno-Economic Modelling and Analysis of an Evolution of Bidding Zones for Wholesale Electricity Markets in the European Power System.

**Keywords :** Wholesale Electricity Markets, Power Transmission, Clustering, Renewable Energy Sources.

**Abstract :** In Europe, wholesale electricity markets follow a zonal market design, where bidding zones are generally defined according to national borders. Within these areas, market players are free to trade electricity with no constraint in volume, in relation to a uniform wholesale electricity price. On the other hand, exchange capacities between zones are limited, both for export and import, according to thresholds that are representative of the physical constraints that apply on the transmission system. In line with the Clean Energy Package and the network codes introduced by the European Commission, transmission system operators are now encouraged to provide as much trading capacity as possible between European national markets, even if this means defining short-term action plans to reduce grid constraints.

In the event of persistent structural congestion, further splittings of market areas will be considered, which has already been addressed several times by transmission system operators and regulation authorities. As a matter of fact, bidding zone delineation significantly impacts the activity of European energy companies, whose operation and investment decisions regarding production assets are highly dependent on market design. The objective of this thesis is therefore to propose a techno-economic modelling and analysis of bidding zone evolution scenarios for the European power system, in order to address their impacts on generation asset portfolios, system operation and costs, price formation and the coordination between grid and generation investments.